National Grid New York Climate Leadership and Community Protection Act Study

Draft Report for Stakeholder Comment

Report for Brooklyn Union Gas Company (KEDNY), KeySpan East Gas Corporation (KEDLI), and Niagara Mohawk Power Corporation (NMPC)

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Disclaimers and Note to Reviewers

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This draft report is being shared with stakeholders for review and input. Guidehouse will continue to review and incorporate findings from the final Scoping Plan and in response to stakeholder feedback from the third stakeholder meeting on November 28, 2022. In addition, Guidehouse will update the report following consideration of comments received during the stakeholder meeting scheduled for January 9, 2023 and written stakeholder feedback submitted by January 17, 2023.

Executive Summary

Background

On July 18, 2019, New York State signed the Climate Leadership Community Protection Act (CLCPA or Climate Act) into law, which mandates that New York State reduce its economy-wide greenhouse gas (GHG) emissions by 40% by 2030 and at least 85% by 2050 from 1990 emissions levels. At the time, the Climate Act was the most ambitious climate legislation that a U.S. state has ever passed, and its implementation will require a transformation of the state's energy systems.

In the August 2021 New York Public Service Commission (Commission) order adopting[1] the Joint Proposal (Downstate Rate Case Order), which established a three-year rate settlement for National Grid's Downstate New York gas distribution companies, The Brooklyn Union Gas Company d/b/a National Grid NY (KEDNY) and KeySpan East Gas Corporation d/b/a National Grid (KEDLI) (collectively called the Downstate Companies), the Commission explained that "… the [Downstate Companies will complete a study evaluating how their businesses may evolve to support the emission reduction and renewable energy goals of the CLCPA and Local Law 97 (the CLCPA Study)."[2] The rate settlement provides that the CLCPA Study be completed by the end of Rate Year 3 (March 31, 2023). Additionally, the Downstate Rate Case Order notes the study should:

> "analyze the scale, timing, costs, and customer bill impacts of achieving significant, quantifiable reductions in carbon emissions from the use of gas delivered in their service territories and the projects and programs needed to achieve the CLCPA's specific decarbonization goals";
>
> "incorporate and respond to any findings or guidance of the New York State Climate Action Council"; and
>
> "Identify potential barriers to achieving the targeted carbon emissions reductions and recommended solutions."

On January 20, 2022, the NYPSC issued its Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements in Cases 20-E-0380 and 20-G-0381[3] (Upstate Rate Case Order) for Niagara Mohawk Power Corporation d/b/a National Grid (NMPC or Upstate Company), which included a similar study requirement in the Joint Proposal In addition to the requirements included in the Downstate Joint Proposal, the Upstate Joint Proposal notes that the CLCPA Study also consider how programs and investments should prioritize emissions reductions in disadvantaged communities.

On December 19, 2022, the New York Climate Action Council released its final Scoping Plan.[4] The final Scoping Plan does not identify specific emissions limits for the buildings sector. However, it does identify key focus areas and recommendations for the buildings sector and gas

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[1] New York Public Service Commission *Order Approving Joint Proposal, As Modified, and Imposing Additional Requirements,* issued and effective August 12, 2021, Case 19-G-0309 and Case 19-G-0310 ("Downstate Order").

[2] Downstate Order at p. 173.

[3] New York Public Service Commission. Order Adopting Terms of Join Proposal, Establishing Rate Plans and Reporting Requirements. Effective January 20, 2022. Case 20-E-0380, 20-G-0381, 19-M-0133.

[4] New York's Scoping Plan, **https://climate.ny.gov/resources/scoping-plan/**

transition. Key discussion elements in the final Scoping Plan with particular relevance to this analysis include:

- Recognition that electrification and energy efficiency will be essential to decarbonization of the buildings sector. The Scoping Plan includes a vision that by 2050, 85% of residential and commercial buildings are electrified "with a diverse mix of energy efficient heat pump technologies, and thermal energy networks,"[5] and recognizes the value of using backup heat sources, particularly in cold areas or to mitigate potential electric capacity constraints.[6]
- Recognition that achieving emissions limits will "entail a substantial reduction of fossil natural gas use and strategic downsizing and decarbonization of the gas system."[7]
- Recognition of the strategic role that renewable fuels may play "to meet customer needs for space heating or process use where electrification is not yet feasible or to decarbonize the gas system as it transitions."[8]
- Recognition that the pace of gas network transition will depend on the pace of customer adoption of alternative heating technologies, and that gas utilities retain an obligation to provide safe and reliable service.[9]

This CLCPA report describes the analytical approach, results, key findings and recommendations for the Downstate and Upstate Companies.

Stakeholder Engagement

To enable public input into the study scope, modeling assumptions, and outputs, and to ensure that important issues could be addressed in a public forum and in the CLCPA Study reports, National Grid held four virtual stakeholder meeting sessions, spread throughout the duration of the study and report process.[10]

Meeting materials were shared at least five days prior to each stakeholder session. In addition to providing feedback during the stakeholder sessions, parties had the opportunity to provide written comments after the stakeholder sessions. Subsequent stakeholder meeting sessions included National Grid and Guidehouse's response to key stakeholder feedback.

[5] Scoping Plan, page 180.

[6] Scoping Plan, page 361.

[7] Scoping Plan, page 350.

[8] Scoping Plan, page 351.

[9] Scoping Plan, page 353.

[10] The first set of stakeholder meetings for Upstate and Downstate New York were held on June 13, 2022 and presented the scope of the study. The second stakeholder meeting was held on August 9, 2022 and reviewed the modeling assumptions and inputs. The third stakeholder meeting was held on November 28, 2022 and reviewed the draft modeling outputs of the study. The fourth stakeholder meeting was held on January 9, 2023 to discuss the draft CLCPA reports and hear stakeholder feedback before they are finalized and published (draft reports shared prior). Due to overlapping content and the two regions' interested parties, National Grid held the second through fourth stakeholder meetings as joint sessions. The CLCPA Study stakeholder meeting materials are available on National Grid's webpage at: **https://www.nationalgridus.com/climate-change-study**

Stakeholder feedback during meetings and in written comments helped guide changes to the scope of the CLCPA study and the resulting analysis.[11]

Table ES-1. Stakeholder Meetings

Meeting	Focus	Date & Time	Presentation Materials
Stakeholder Meeting #1	Scoping	Downstate – July 13, 2022 10 a.m. ET Upstate – July 13, 2022 2 p.m. ET	**Guidehouse Slides** **National Grid Slides**
Stakeholder Meeting #2	Modeling Inputs and Assumptions	August 9, 2022 10 a.m. ET	**Slides**
Stakeholder Meeting #3	Modeling Outputs	November 28, 2022 2 p.m. ET	**Slides**
Stakeholder Meeting #4	Draft Report	January 9, 2023 2 p.m. ET	To be added

Source: Guidehouse

Approach

This study used scenario-based analysis to compare three different visions of the future (i.e., scenarios) and to determine the timing, scale, and cost of meeting the requirements and the statewide GHG limits established by the Climate Act. The scenarios in this analysis were defined by assumptions about how residents, buildings, and industries will use energy in the future to meet their needs around transportation, space conditioning, and production of goods.

The study approach was divided into four phases as described in Table ES-2.

[11] For example, stakeholder feedback informed e the following updates: emissions costs taken from more recently published NYISO source, anaerobic digestion costs aligned with ICF AGF 2019 report, hydrogen storage cost variable added, alignment of battery types with ABT 2022 classifications, GSHP efficiency values aligned with NYSERDA Heat Pump Study, hydrogen boiler costs added, efficiency assumptions added for hydrogen boilers, hydrogen infrastructure costs added, in-state methane distribution costs added, industry energy demand for CEV scenario aligned with Scenario 2 of the Integration Analysis, Op-Co level energy consumption forecast economic drivers added, and leak-prone pipe quantities in service territories were added. This list is not exhaustive but covers the main categories that incorporated stakeholder feedback.

Table ES-2. Overview of Study Methodology

Phase 1: Scenario Definition	Phase 2: Demand Forecasting
Defined each scenario in terms of assumptions about future energy use patterns and technology adoption trends.	Estimated the end-use demand for different sectors and energy carriers, accounting for the effects of energy efficiency and other demand-side management interventions, electrification, and fuel switching.
Phase 3: Energy System Modeling	**Phase 4: Cost Modeling**
Determined the production capacity and the supply side developments that would be needed to meet energy demand in each scenario, including the development of new energy generation facilities and investments in transmission and distribution infrastructure needed to connect energy supply to demand.	Estimated the demand-side and supply side costs that will be incurred to transition from the current state to the scenario outcome.

Source: Guidehouse

To model the energy systems needed to supply the forecasted demand, this study used an integrated energy system model, Guidehouse's Low Carbon Pathways (LCP) model. This model was adapted to the characteristics of New York's gas and electricity networks, including its energy supply-demand conditions, and its interties with neighboring regions. For each scenario, the LCP model selects a least cost pathway for the electricity and gas systems and identifies the investments that would be necessary to expand and maintain the systems to produce and deliver electricity, hydrogen, and methane. The pathways describe investments in generation and supply capacity, storage, and infrastructure, as well as when those investments will be needed.

Analysis Scenarios and Modeling Assumptions

Each of the three scenarios meet the requirements established by New York's Climate Act, including gross GHG emissions limits in 2030 and 2050 and necessary new renewable electricity generation and electricity storage capacity. Two scenarios were adapted from the CAC's Integration Analysis: The **Strategic Use of Low-Carbon Fuels** scenario (Integration Analysis Scenario #2) and the **Accelerated Transition Away from Combustion** scenario (Integration Analysis Scenario #3).[12] A third scenario, the **Clean Energy Vision-New York** scenario (hereafter, "CEV.NY"), was based on National Grid's April 2022 publication describing a future where existing gas infrastructure supports the delivery of low carbon fuels.[13] Table ES-3 compares the defining parameters of the three scenarios.

[12] NY Climate Action Council (December 2021). Draft Scoping Plan, Appendix G. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scoping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.pdf**

[13] National Grid (April 2022). "Our clean energy vision: A fossil-free future for cleanly heating homes and businesses." Available at: **https://www.nationalgrid.com/document/146251/download**

Table ES-3. Scenario Assumptions by Demand Sector

<table>
<tr><th>Sector</th><th>Strategic Use of Low-Carbon Fuels (CAC#2)</th><th>Accelerated Transition Away from Combustion (CAC#3)</th><th>Clean Energy Vision-New York (CEV.NY)</th></tr>
<tr><td rowspan="3">Buildings</td><td>92% of residential and commercial buildings are electrified by 2050.

Electrification is 70% air-source heat pump (ASHP), 20% ground-source heat pump (GSHP), and 10% hybrid heat.</td><td>92% of residential and commercial buildings are electrified by 2050.

Electrification is 77% ASHP, 23% GSHP, with no hybrid heat.</td><td>Networked geothermal serves 4% of NYC and 8% of non-NYC housing units.

20% of non-residential customers convert to 100% hydrogen heat by 2050.

75% of housing units are electrified by 2050, split as:
<table><tr><th></th><th>NYC</th><th>Other</th></tr><tr><td>Hybrid</td><td>76%</td><td>48%</td></tr><tr><td>ASHP</td><td>16%</td><td>39%</td></tr><tr><td>GSHP</td><td>8%</td><td>13%</td></tr></table>
70% of commercial building space is electrified by 2050, split at 65% hybrid heat, 20% ASHP, and 15% GSHP.</td></tr>
<tr><td colspan="3">Building efficiency improvements reduce heating and cooling loads by 31% from 2020 to 2050</td></tr>
<tr><td colspan="2">Remaining non-electric energy demand served by renewable natural gas (RNG) and low-carbon fuels (e.g., biofuel).

No hydrogen blending in pipeline gas.</td><td>Remaining gas demand served by RNG/hydrogen blend, increasing to 7% hydrogen (by energy) by 2050</td></tr>
<tr><td rowspan="2">Industry</td><td colspan="3">Industry efficiency improvements reduce annual energy consumption 40% from 2020 to 2050</td></tr>
<tr><td>33% of gas use is electrified by 2050.
Remaining gas use is served by hydrogen.</td><td>83% of gas use is electrified by 2050.
Remaining gas use is served by hydrogen.</td><td>33% of gas use is electrified by 2050.
Remaining gas use is served by hydrogen.</td></tr>
<tr><td rowspan="2">Transport</td><td>By 2050:
Light duty vehicle (LDV) stocks are 95% ZEV,
Medium- and heavy-duty vehicle (MDHD) stock is 77% ZEV</td><td>By 2050:
LDV stocks are 96% ZEV, MDHD stock is 86% ZEV</td><td>By 2050:
LDV stocks are 95% ZEV, MDHD stock is 77% ZEV</td></tr>
<tr><td colspan="3">Marine and ports are fully electrified by 2050</td></tr>
<tr><td>Agriculture</td><td colspan="2">Changes to animal feed yield 24% decrease in annual livestock methane emissions from 2020 to 2050</td><td>Changes yield 50% decrease in annual livestock methane emissions from 2020 to 2050</td></tr>
<tr><td rowspan="2">Waste</td><td colspan="2">Methane capture at landfills reduces annual landfill methane emissions by 70% from 2020 to 2050</td><td>Landfill methane emissions reduced 75%, 2020 to 2050</td></tr>
<tr><td colspan="2">Wastewater methane capture reduces annual wastewater methane emissions by 25% from 2020 to 2050</td><td>Wastewater methane emissions reduced 65%, 2020 to 2050</td></tr>
</table>

Source: Guidehouse analysis and NY CAC (December 2021)[14]

The scenario parameters differed by geography according to the different demand profiles and technology mixes that exist today. The applicability and technical feasibility of zero- and low-carbon replacements and the influence of local policies such as NY City's Local Law 97 varied by region. In addition, the more prevalent use of heating oil Upstate will inform the energy profiles of the region and how they can decarbonize. Networked geothermal may most suitable for development in areas where there is relatively close customer proximity, suitable soil characteristics, and pipelaying is not prohibitively expensive (e.g., in a suburb). All of these factors informed the demand forecasts for the regions analyzed in this study.

For the two scenarios from the New York State Climate Action Council's (CAC) Integration Analysis, Guidehouse referenced the extensive assumptions workbooks published by the NY CAC. For the CEV.NY scenario, Guidehouse compiled assumptions based on input from National Grid, a review of modeling assumptions from the CAC Integration Analysis and the Massachusetts 20-80 proceeding, Guidehouse internal expert judgement, and secondary research.

The CEV.NY scenario assumptions were based on the four strategic pillars of National Grid's Clean Energy Vision. Table ES-4 describes these pillars and the specific scenario assumptions informed by the pillars. The CEV.NY scenario was distinguished from the Integration Analysis scenarios in its assumptions for the buildings sector, for which the CEV.NY scenario assumed higher rates of partial building electrification and a greater role for hydrogen and Renewable natural gas (RNG). For the industry and transportation sectors, the CEV.NY scenario adopted the same assumptions as the Strategic Use of Low-Carbon Fuels scenario.[15]

This analysis leveraged the sources and assumptions cited in the CAC Integration Analysis for most baseline modeling assumptions, including overarching economic drivers such as population growth, building stock turnover, and technoeconomic characteristics. This study incorporated assumptions specific to National Grid in cases where the Integration Analysis did not provide data, where Integration Analysis data was out-of-date, or where utility-specific data is more relevant than the CAC's statewide assumptions.[16] In cases where neither National Grid nor the Integration Analysis provided applicable inputs or assumptions for a topic, Guidehouse used internal expert research and judgement to develop assumptions.

The Inflation Reduction Act (IRA) provides incentives in the form of tax credits to several clean energy technologies, including traditional renewables, electric vehicles, biodiesel, renewable natural gas, carbon capture, hydrogen, and energy efficiency, among others. The IRA is expected to have widespread impacts on the deployment of clean energy resources across the energy system. While the timeline of the IRA's passage did not provide sufficient time to conduct a comprehensive revision of the modeling used in this study, the potential cost impacts of relevant provisions were evaluated qualitatively.

[14] See: NY CAC (December 2021). "Draft Scoping Plan Appendix G," Sections 2.1 and 5.3. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scoping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.pdf**

[15] The Strategic Use of Low Carbon Fuels scenario assumptions for industrial and transportation sectors align with the strategic pillars of the Clean Energy Vision, in that the scenario assumes the industrial and transportation are decarbonized using a mix of electricity and renewable fuels, and that renewable fuels are used to mitigate growth in peak electric demand.

[16] For instance, National Grid's Gas Load Forecasting Team provided forecasts of annual gas consumption and design day demand at the operating company (OpCo) level, with input from the Guidehouse pathways assumptions.

Table ES-4. CEV.NY Scenario Assumptions Based on Clean Energy Vision Pillars

Pillars of National Grid's Clean Energy Vision[17]	CEV.NY Scenario Assumptions
1. Energy Efficiency in Buildings—continuation of programs to help customers accelerate energy efficiency improvements to buildings, ranging from deep retrofits to the support of more rigorous building codes for new buildings.	The CEV.NY scenario assumed that energy efficiency improvements will lead to a 30% reduction in building space heating and space cooling loads by 2050. This assumption is consistent with the Integration Analysis scenarios.
2. Fossil Free Gas Network—elimination of fossil fuels from existing gas network by 2050 through the substitution of renewable natural gas and green hydrogen.	The CEV.NY scenario assumed that gas deliveries will transition from fossil fuels to a mix of RNG and hydrogen, and that 20% of non-residential customers will transition to 100% hydrogen gas service by 2050. CEV.NY assumed that hydrogen blending in pipeline gas is assumed to reach 20% of total gas volume by 2050.
3. Hybrid Electric-Gas Heating Systems—continuation of support for customers by providing strategies and tools to capture and maximize the benefits of pairing electric heat pumps with existing gas appliances.	The CEV.NY scenario assumed that by 2050, over 40% of residential and commercial buildings will transition to hybrid heating systems that combine an electric ASHP with a gas-fired heating system.
4. Targeted Electrification and Networked Geothermal—piloting new solutions like networked geothermal to help support cost effective targeted electrification of the gas network as well as providing support to customers using oil and propane with strategies to convert to heat pumps	The CEV.NY scenario assumed that by 2050, networked geothermal systems will serve 7% of customers, equal to roughly 630,000 households and 400 million square feet of non-residential building space statewide.

Source: Guidehouse analysis and National Grid (2022)[18]

Cost Modeling Approach

After identifying the least cost pathway for each scenario from a total cost perspective, Guidehouse calculated an annual revenue requirement as the sum of levelized upfront and ongoing generation, transmission, and distribution (T&D) costs. Then, two main categories of cost to end-user customers were quantified in this study: (1) end-user investment in energy efficiency upgrades and heating equipment, and (2) the cost of energy bills. The end-user efficiency and equipment costs applied assumed unit costs to the level of efficiency and heating equipment upgrades identified in each scenario. The energy bill was estimated using assumed usages per customer, multiplied by the supply and delivery price metric estimates. Given the caveats to this simplified estimate of energy prices, the estimates of energy bills are intended to be indicative and allow for comparison across scenarios, absent changes to depreciation approaches or other reforms.

[17] National Grid (April 2022). "Our clean energy vision: A fossil-free future for cleanly heating homes and businesses." Available at: **https://www.nationalgrid.com/document/146251/download**

[18] National Grid (April 2022). "Our clean energy vision: A fossil-free future for cleanly heating homes and businesses." Available at: **https://www.nationalgrid.com/document/146251/download**

Findings and Considerations

1. **To meet the state's climate goals, energy sources across New York's economy must change.** To meet the CLCPA's limits on gross GHG emissions, all scenarios in this analysis assumed that a high degree of electrification will take place in the buildings, industry, and transportation sectors. All scenarios assumed that a portion of energy use in New York will shift from geologic natural gas to RNG and hydrogen. In the Integration Analysis scenarios, energy use in the buildings sector is almost fully electrified, while the CEV.NY scenario complements electrification with the deployment of hybrid heating systems (fueled by electricity and RNG) and pure hydrogen systems. All scenarios assumed that industry sector gas use shifts to a mix of electricity and hydrogen. These scenario design choices influence the demand forecasts for each scenario and provide input to the capacity expansion modeling conducted in this study. All three scenarios modeled in this analysis are compliant with CLCPA emissions limits.

2. **Energy efficiency improvements are needed to achieve New York's climate goals in each of the scenarios studied.** To achieve stated outcomes in the Climate Law, all three scenarios modeled in this analysis assumed a significant improvement to the energy efficiency of buildings, industrial processes, and other end uses of energy. Scenarios assumed that by 2050, energy efficiency will reduce building space conditioning energy needs by 30% and will reduce industrial process energy needs by 40%. As with heating system assumptions, these energy efficiency assumptions are scenario design choices that influence the demand forecasts. This analysis projects that over $100 billion (2020$ net present value) of investment in building retrofits will be needed to by 2050. These improvements and the conversion of fuel-fired vehicles and heating equipment to electric equipment will reduce economy-wide energy use.

3. **Affordability and equity considerations must be prioritized and addressed.** As New York transitions its energy grid, an important consideration for National Grid is to ensure that the change does not unequally benefit certain groups while proving a detriment to others. A variety of factors, including income, location, home age, surrounding environment, and access to information can all influence whether certain groups are willing and able to transition from gas to electricity; higher-income households will likely transition to electrification more quickly due to their ability to afford the upfront costs of electric heating equipment and efficiency upgrades. Absent policies and measures to assist low-income and DACs with the energy transition, the customers remaining on the gas system are therefore more likely to be low-income and disadvantaged communities (DAC) households that, barring regulatory intervention, will be left to pay higher rates for gas system maintenance due to fewer customers on the system. These issues present notable challenges that must be thoughtfully approached by policymakers, regulators, and utilities to ensure that the benefits of the transition are equitably distributed across the entirety of the state's population and that at least 35% of benefits of clean energy investments accrue to disadvantaged communities. Furthermore, when new energy infrastructure development is considered in DACs, enhanced efforts and stakeholder engagement may be needed to ensure that adverse impacts are minimized and that community benefits are maximized.

4. **All scenarios require significant investment in electricity infrastructure.** New York's electricity supply capacity is projected to increase over threefold in all scenarios due to several factors: (1) High rates of electrification in all energy-using sectors will lead to increased peak electricity demand, requiring new generation capacity. (2) The shift from

natural gas-fired electric generation resources (with relatively high capacity factors) to intermittent renewable resources (with lower capacity factors) will need an increase in nameplate electricity generation capacity. All three scenarios also project a scale up of electric T&D infrastructure and energy storage capacity.

5. **The energy transition will be costly, but relative to other scenarios a diversified approach to building sector decarbonization offers opportunities to lower energy system and customer costs.** A large amount of investment will be needed to extend and upgrade New York's energy systems, to retrofit customer buildings, and to replace energy consuming appliances. This analysis estimates the net present value of the energy transition costs from 2020-2050 will range from $0.95 trillion to $1.05 trillion. Compared to the Integration Analysis scenarios, the CEV.NY scenario will have lower total NY State system costs due to lower energy system costs and more diverse investment that will occur across sectors and later in time. The CEV.NY scenario will also rely less on investment in customer-side heating equipment conversions than the Integration Analysis scenarios.

6. **Renewable gas (RNG and hydrogen) will have a role in all scenarios.** The Climate Act's emissions requirements cannot be achieved cost-effectively through electrification alone. Low- and zero-carbon gases like RNG and hydrogen will play a role in GHG emissions reductions, particularly in sectors such as heavy transportation or certain industrial processes that will be challenging to decarbonize through electrification. RNG may be used as a drop-in replacement for geologic natural gas that is distributed today to progress gas network decarbonization. Dedicated hydrogen infrastructure will be necessary to connect hydrogen producers to customers who convert to pure hydrogen service.

7. **Coordination across energy systems will be necessary to transition quickly and at scale.** Such coordination is essential on multiple fronts to accelerate market adoption towards decarbonization. First, coordinated gas and electric system planning will be necessary to advance targeted electrification and optimize infrastructure investments. Second, customer adoption of hybrid heating technologies provides an opportunity for utilities to develop strategies to efficiently utilize both gas and electric infrastructure and manage peak demand. Finally, electricity will be used to produce green hydrogen supply, which will also be critical in meeting peak electricity demand through hydrogen-fired gas turbines.

8. **A strategy that incorporates hybrid heating systems can mitigate electric peak demand growth.** All scenarios project an increase in electric peak demand. Peak electric demand is projected to double by 2050 in the Integration Analysis scenarios, compared to a 60% increase in peak demand in the CEV.NY scenario. Coincident peak electric demand grows less in the CEV.NY scenario than the Integration Analysis scenarios due to increased adoption of hybrid heating systems. As a result, the CEV.NY scenario entails roughly 10% less investment in new electric generation capacity and roughly 40% less investment to build out electric T&D than the Integration Analysis scenarios.

9. **Regulatory and policy reforms will be needed to maintain reasonable gas utility rates for customers.** In all scenarios, gas customer counts and delivery volumes are projected to decline. Total gas use and customer counts decline less in the CEV.NY scenario, which repurposes existing gas infrastructure to deliver renewable, low-carbon

gas. Under the current regulatory environment, with no cost sharing across energy systems, per therm or per customer thermal system costs begin to grow significantly starting around 2040. If the energy transition described in the findings above is not accompanied by a regulatory transition, then gas utilities' normalized revenue requirement per customer is projected to increase at least threefold. Policy will need to shape who pays for the energy transition and define how costs are socialized while protecting disadvantaged communities.

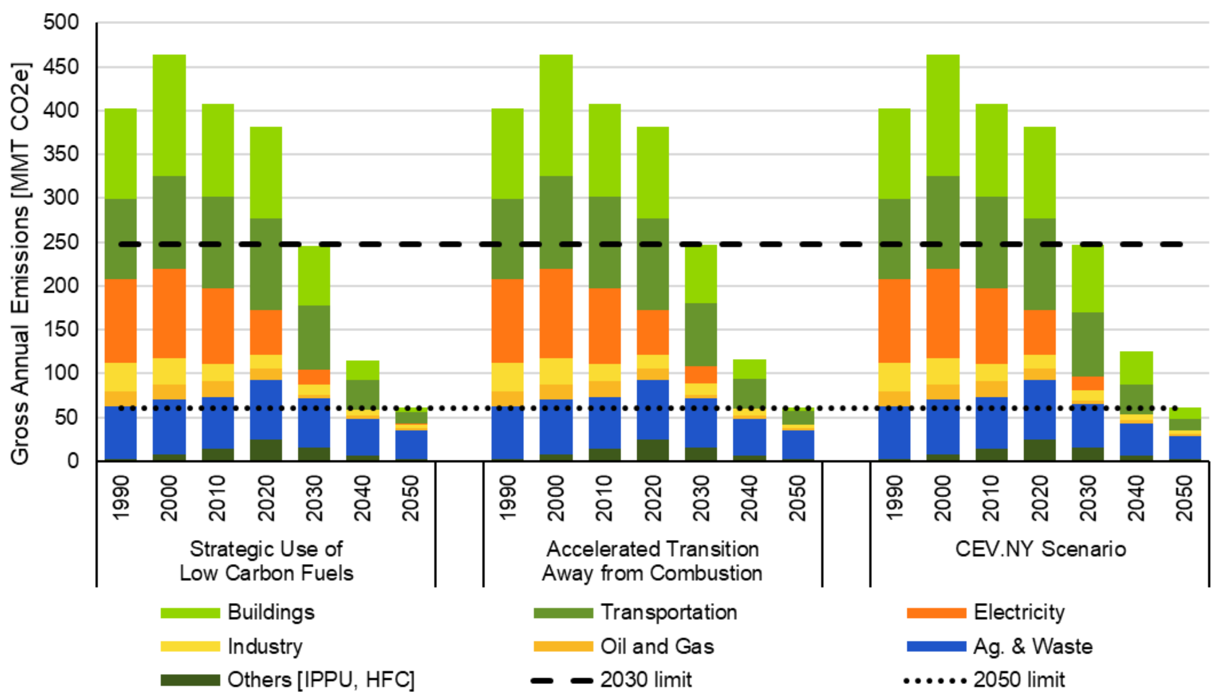
10. **Combustion generation will maintain a critical role in New York's electricity system.** Today, natural gas turbines support electric system reliability by serving as a dispatchable resource. In a CLCPA-compliant future, all scenarios project that hydrogen-fired turbines will be used to meet peak demand and ensure system reliability. These peaking resources will be critical during long periods with little or no electricity generation from wind. Without hydrogen-fired generation, it will be more difficult to achieve a net zero electricity system. A greater amount of combustion generation will be needed in scenarios with greater degrees of space heating electrification.

Analytical Results

In each of the three modeled scenarios, GHG emissions are projected to decline to meet the Climate Act's GHG 2030 and 2050 emissions targets.[19] In the energy consuming sectors of the economy (buildings, industry, and transportation), GHG emissions reductions are driven by energy efficiency, electrification, and the substitution of RNG and hydrogen for fossil fuels. For buildings, electrification of heating devices, such as air-source heat pumps, building shell upgrades, and usage of RNG in lieu of natural gas are the main factors behind emissions reductions between 2020 and 2050. In the industry sector, electrification, energy efficiency improvements, and the substitution of hydrogen for fossil fuels drives the projected decrease in GHG emissions.

From 2020 to 2050, gross GHG emissions from the buildings sector decrease by 94.8% in the Strategic Use scenario, by 95.7% in the Accelerated Transition scenario, and by 88.3% in the CEV.NY scenario. Compared to the Integration Analysis scenarios, the CEV.NY scenario assumed the buildings sector will produce more emissions in 2050 under a gross emissions accounting approach due to lower rates of whole-building electrification and greater consumption of RNG for space heating and other end uses.

Figure ES-1. Gross GHG Emissions by Scenario and Source, 2020-2050



Note: Years 1990-2010 are historical data reported in DEC New York State Emissions Inventory.[20] Years 2020-2050 are modeled emissions based on scenario demand forecasts.

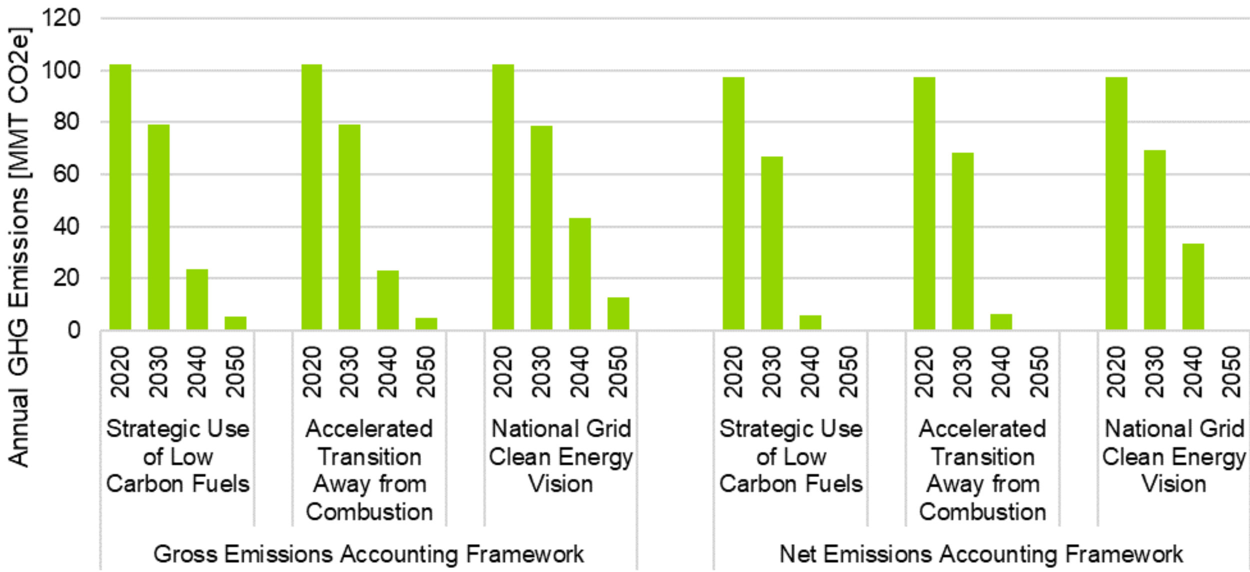
Source: Guidehouse analysis

[19] This analysis calculated GHG emissions in a manner consistent with the New York DEC's draft accounting framework

[20] New York DEC (2021). "2021 Statewide GHG Emissions Report" Available at: **https://www.dec.ny.gov/energy/99223.html**

Figure ES-2 below compares GHG emissions from the buildings sector, calculated under a gross emissions framework and a net emissions framework. This comparison illustrates that under a net emissions accounting framework, which is inclusive of avoided methane emissions and counts RNG as GHG-neutral, the buildings sector achieves net zero emissions in 2050 for all scenarios.

Figure ES-2. Buildings Sector GHG Emissions, Gross and Net GHG Accounting Frameworks (2020-2050)



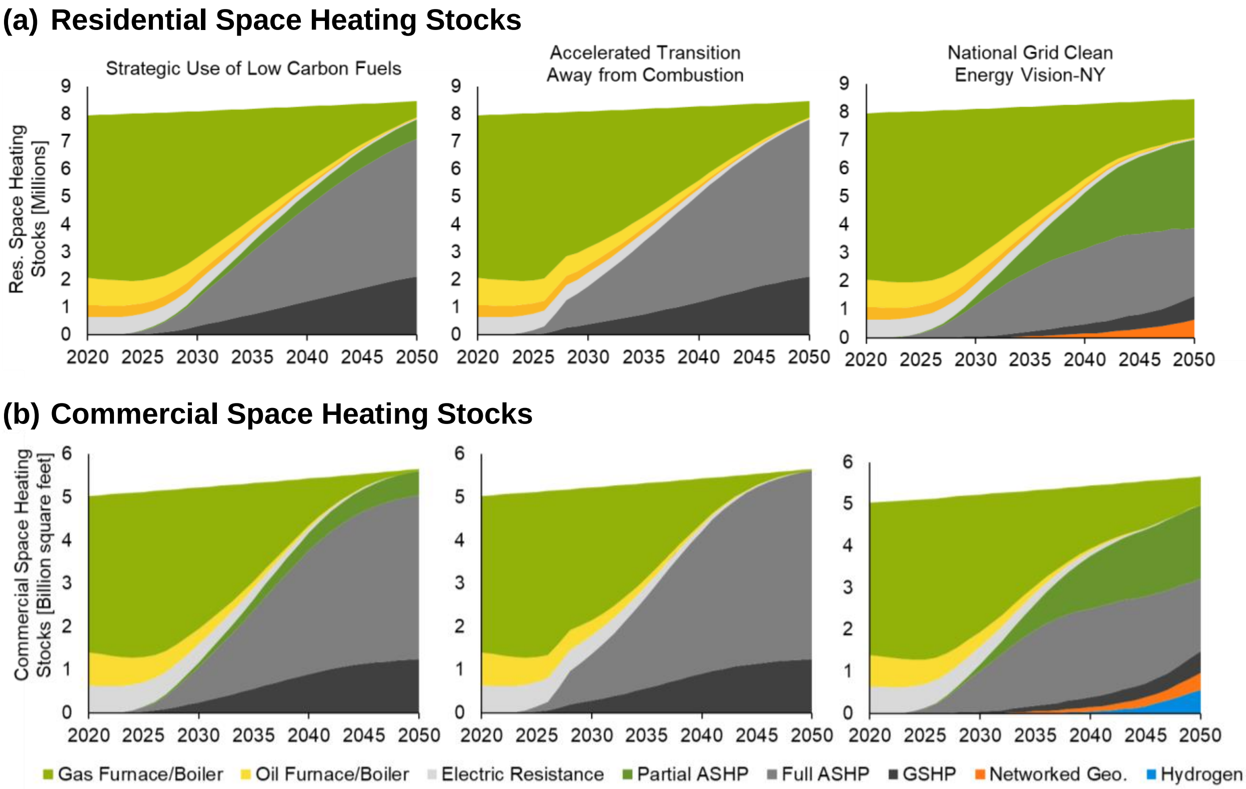
Source: Guidehouse analysis

Building Heating System Adoption

The three scenarios have different assumptions about how energy usage in New York will shift over time. The type of heating system has a large impact on customer energy demand, and Table ES-2 illustrates the differences in these assumptions by scenarios for residential and commercial customers. There are three main differences between the CEV.NY scenario and the Integration Analysis scenarios:

- The CEV.NY scenario had a much larger role for hybrid heating systems (also referred to as partial heat pumps), with hybrid heating systems making up about 35% of heating system stocks in 2050.
- The CEV.NY scenario assumed a larger portion of customers will retain high efficiency gas-fired systems.
- The CEV.NY scenario assumed a more gradual adoption of geothermal heating systems and assumed that the share of customers who adopt geothermal heating systems will be split between standalone ground-source heat pumps (labeled as GSHP) and networked geothermal systems.

Figure ES-3. Statewide Residential and Commercial Heating System Stocks, 2020-2050

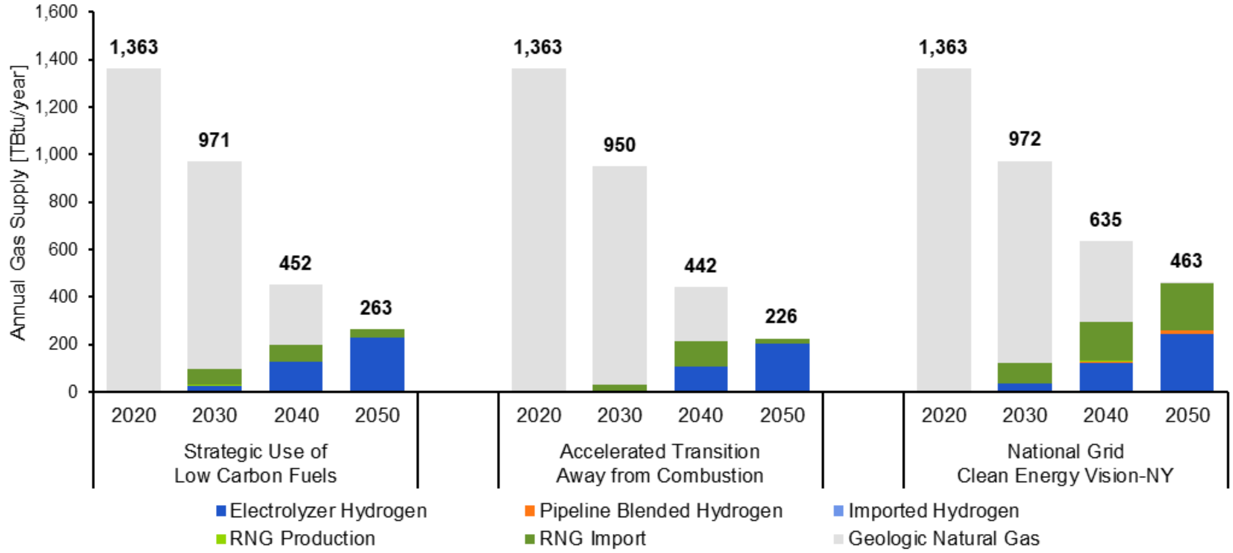


Source: Guidehouse analysis

Gas Supply Development

All scenarios projected a decline in annual gas supply from 2020 to 2050 (Figure ES). The Integration Analysis scenarios projected an 81-83% drop in gaseous fuel consumption by 2050. The Integration Analysis scenarios also projected that hydrogen will meet most demand for gaseous fuels, with a small amount of demand met by RNG imported from out of state. In contrast, the CEV.NY scenario forecasted a 66% decline in gaseous fuel consumption from 2020 to 2050, with gaseous fuel supplied in 2050 split between green hydrogen and RNG. All scenarios assume that the components of fuel supplied via pipeline distribution networks will shift over time, from 100% geologic natural gas in 2020 to 100% renewable gas (RNG or hydrogen) in 2050.

Figure ES-4. NY Statewide Gas Supply Mix (TBtu/year)



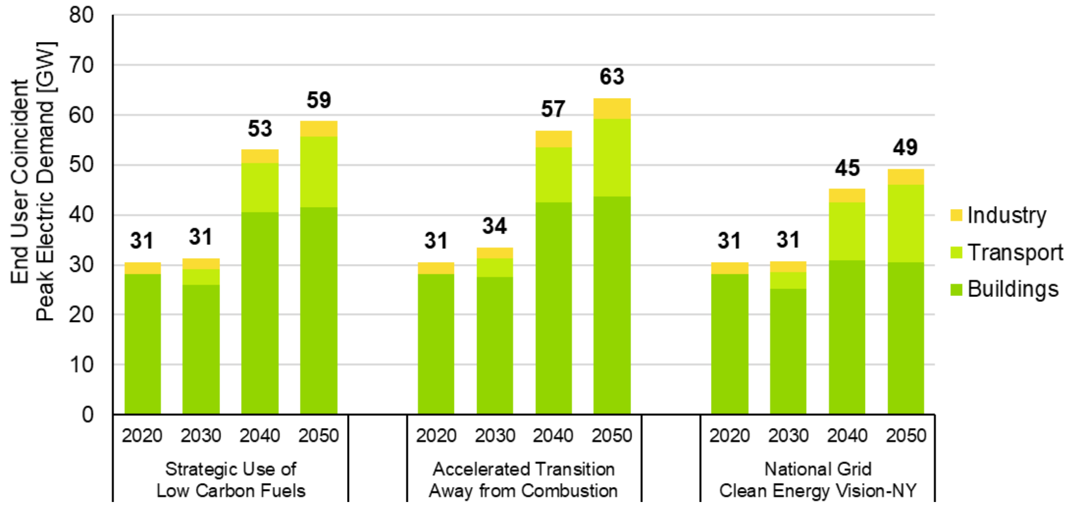
Note: Figure includes gaseous fuels supplied via existing natural gas distribution networks and direct supplies of 100% hydrogen.

Source: Guidehouse analysis

Electric Peak Demand and Electricity Supply Development

To meet the forecasted increase in electricity demand in the coming decades, the statewide nameplate electricity supply capacity is projected to increase over threefold in all scenarios due to the high level of electrification across all energy consuming sectors, and the difference in capacity factors between the gas-fired systems in use today and the renewable capacity planned for the future. Figure ES-5 shows the statewide annual coincident peak demand, which shows the highest increases in the Accelerated Transition Away from Combustion scenario due to full reliance on electric heat pumps and lowest increase for CEV.NY due to a higher portion of hybrid heating systems that meet a portion of peak heating load using combustion.

Figure ES-5. Statewide Annual Coincident Peak Demand for End-User (i.e., Direct) Electric Consumption

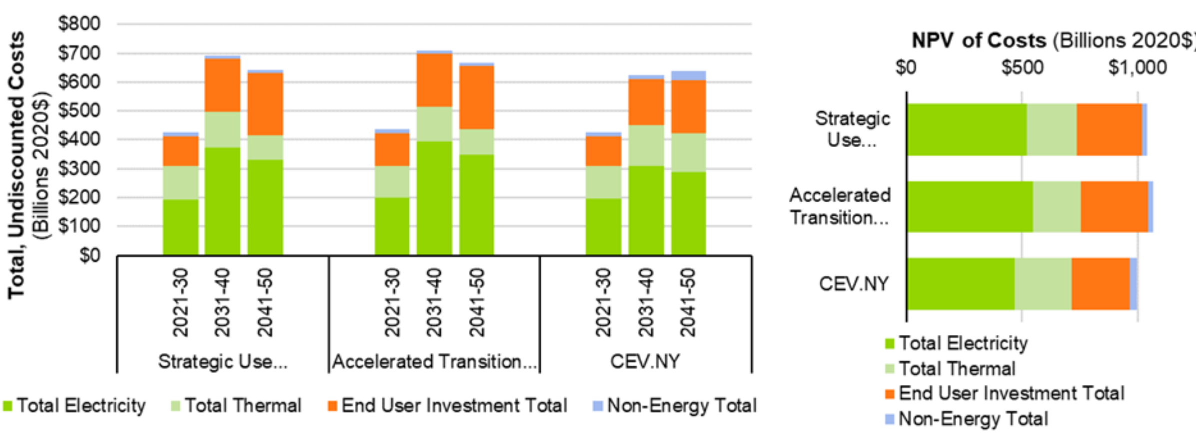


Source: Guidehouse analysis

Costs

A comparison of the total cost of each modeled scenario is shown below. In total, the CEV.NY scenario has lower costs than the other scenarios, driven largely by lower end-user heating equipment costs and avoided electric infrastructure costs, though a portion of this cost savings is offset by relatively greater investment the thermal network and in non-energy investments.

Figure ES-6. Total Analyzed New York State Expenses by Scenario



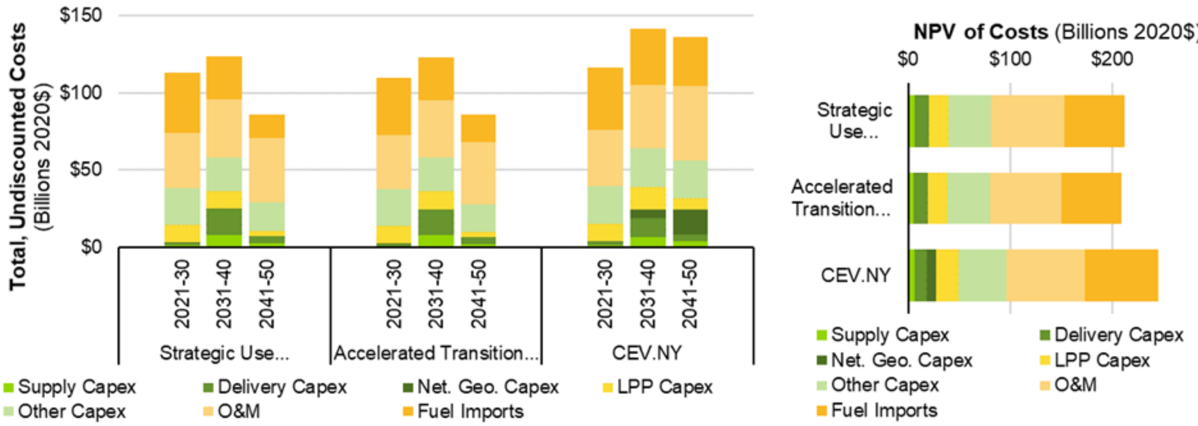
Note: See Section 3.7 for complete breakdown of costs by category, and Section 2.6 for description of cost estimation. Upfront plus ongoing costs incurred between 2020-2050 included. Net present value (NPV) assumes real discount rate of 3.6%.

Source: Guidehouse analysis

Statewide Energy System Costs

Comparing the thermal system costs across scenarios, the CEV.NY scenario includes relatively greater investment later in the analysis period, primarily in the form of networked geothermal. In addition to continued O&M and fuel import costs, as well as slightly higher leak-prone pipe replacement costs, the CEV.NY scenario calls for more thermal system costs than the Integration Analysis scenarios. Note that this study does not consider the incremental costs of decommissioning thermal network segments that may vary by scenario. These would include the cost of removal of system pipe and related equipment where necessary, environmental cleanup costs, regulatory costs, and costs associated with maintaining the safe and reliable operation of remaining network segments during the decommissioning process.

Figure ES-7. Total Thermal System Costs

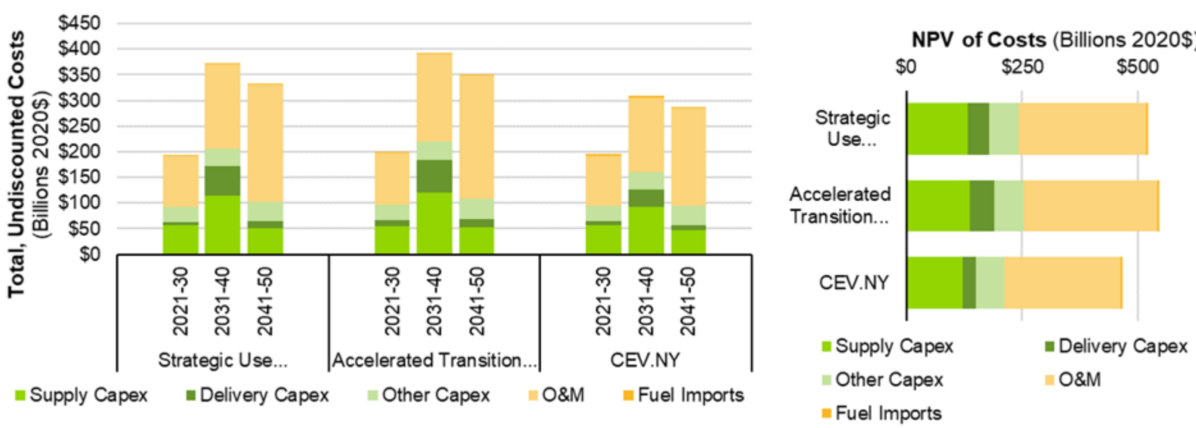


Note: Upfront plus ongoing costs incurred between 2020-2050 included. Thermal network fuel imports include cost of imported NG/RNG/H2 used for electric generation. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

While the CEV.NY scenario calls for greater investment in the thermal energy network, the Integration Analysis scenarios call for greater electric energy network costs. This is primarily driven by increased delivery capital expenses necessary to meet increased electric peak demand, which includes transmission and distribution capacity.

Figure ES-8. Total Electric System Costs



Note: Upfront plus ongoing costs included. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

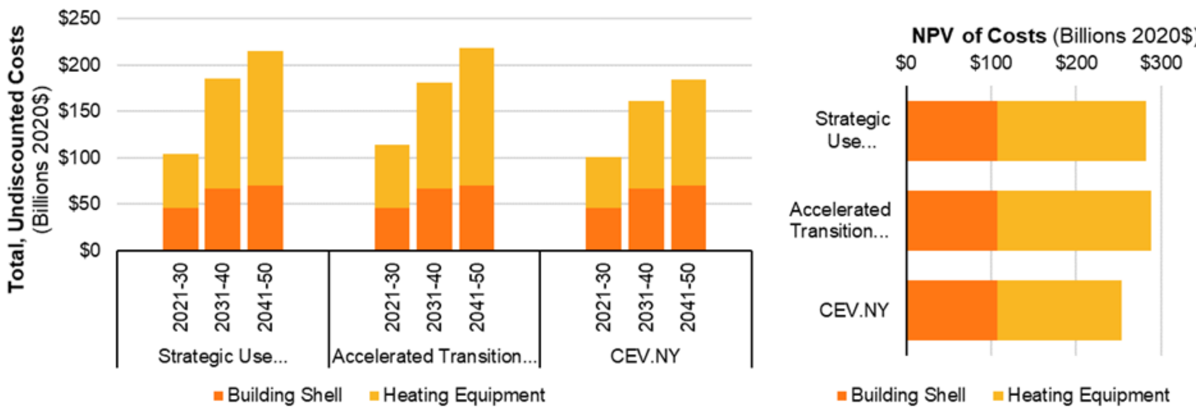
Customer Costs

This analysis considered two key costs to customers of the energy transition: (1) investment in heating system equipment and efficiency measures, and (2) customer bill impacts of space heating.

Customer Equipment Investment Costs

The total cost of building shell upgrades and new heating equipment assumed in each scenario across NY State is shown below. Note that these costs exclude any state or federal incentives to reflect total cost to the state; statewide incentives and some portion of federal incentives would in effect be paid for by NY State taxpayers.[21] The CEV.NY scenario has the lowest relative costs, because it calls for less electrification and therefore less heat pump installations, which are assumed to be higher cost over the analysis period.

Figure ES-9. Total Customer Investments



Note: Total upfront costs included (excludes any state or federal incentives). Includes costs to both residential and C&I customers. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

Indicative Customer Bill Impacts

The total energy system investment and ongoing costs are found to be lower in the CEV.NY scenario than the Integration Analysis scenarios. A key consideration, however, is how the bills of customers using different heating sources change over the analysis period.

Assuming no changes to current straight-line depreciation approaches, indicative space heating bills for remaining thermal customers increase around 2040 through 2050 in each scenario: bills are 2-4x above 2020 levels across National Grid territories under the CEV.NY scenario in 2050; and 6-10x above 2020 levels across National Grid territories under the Integration Analysis scenarios in 2050. . These results illustrate the affordability challenge that will exist for remaining gas network customers absent regulatory changes to address long-term affordability during the transition   Reforms to depreciation approaches to accelerate recovery or better align recovery of depreciation expense with network utilization would increase customer bills in the

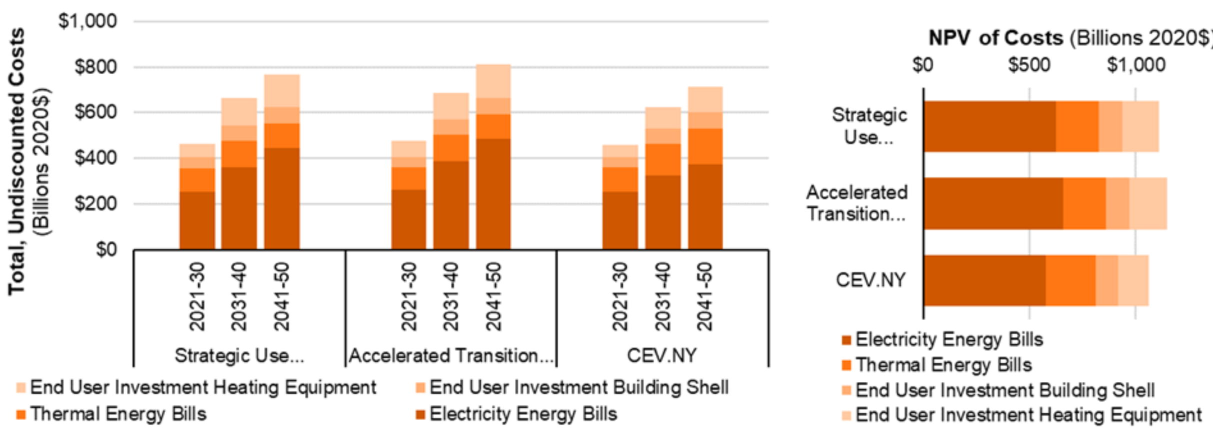
[21] The extent to which New York State taxpayers are a net contributor or net beneficiary of federal funds such as IRA is unknown, so this analysis effectively assumes that IRA benefits to New York are equal to its revenue contributions that fund these provisions.

near term but reduce long-term bill impacts. This report further provides further discussion of this issue as well as key findings from the Companies' November 2022 analysis of the impacts of modified approaches to depreciation and its potential impacts on customers based on the potential impacts of CLCPA targets on gas throughput and customer counts.[22]

Total Customer Costs

Combining the upfront customer investment costs and ongoing customer energy bill impacts yields the total cost to customers, presented below. Electric energy bills are calculated in the same way as thermal energy bills: unitized estimated annual electric revenue requirement times the demand for electricity in each scenario. The CEV.NY has the lowest total cost to customers, due to both the lower cost of heating equipment in that scenario and the lower total energy bills. The CEV.NY scenario shows higher total thermal energy bills, but the relatively higher cost is offset by lower total electric energy bills.

Figure ES-10. Total End-User Customer Costs



Note: Total upfront costs included (excludes any state or federal incentives). Includes costs to both residential and C&I customers. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

Operating Company Summary Findings

The following figures summarize the findings for each operating company, including the following projections:

(1) The projected **gas consumption** supplied by National Grid's distribution networks, showing the change in gas consumption from 2020 to 2050 for all three scenarios, and including geologic natural gas, RNG, pipeline-blended hydrogen, and pure hydrogen supplies.

(2) The projected **counts of customers** on National Grid's gas distribution networks in Upstate and Downstate New York.[23] In these stacked column charts, the total heights of the columns show National Grid's unadjusted baseline forecasts of retail customers. In other words, the

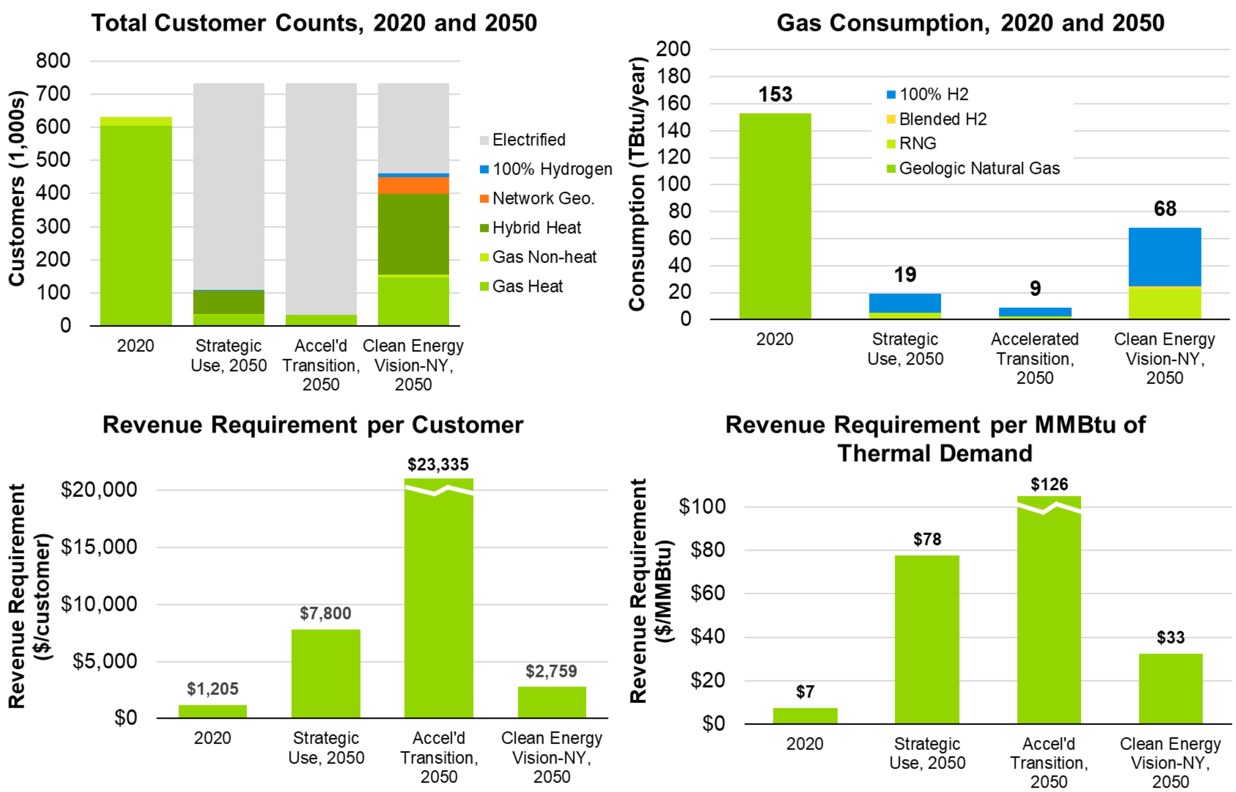
[22] New York Department of Public Service. Case 19-G-0678. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-g-0678.

[23] Residential and non-residential customer counts are disaggregated in the main body of this report. National Grid's unadjusted baseline forecasts include increases in meter counts due to population growth and the addition of new customers converting from delivered fuel (e.g., fuel oil) heating systems.

column heights show the projected number of customer meters that National Grid would serve in the absence of New York's Climate Act. The gray portions of each column indicate customers projected to leave the gas network due to electrification.

(3) The **normalized revenue requirements**, expressed in terms of dollars per customer and in terms of dollars per unit of thermal demand. The revenue requirement per customer reflects an illustrative trajectory of customers' annual bills under the current regulatory environment, averaged across all customer types and usages. The revenue requirement per unit of thermal demand reflects the trajectory of the delivered price of thermal energy under the current regulatory environment, again averaged across all customer types. [24]

Figure ES-11. Summary Findings for Niagara Mohawk Operating Company

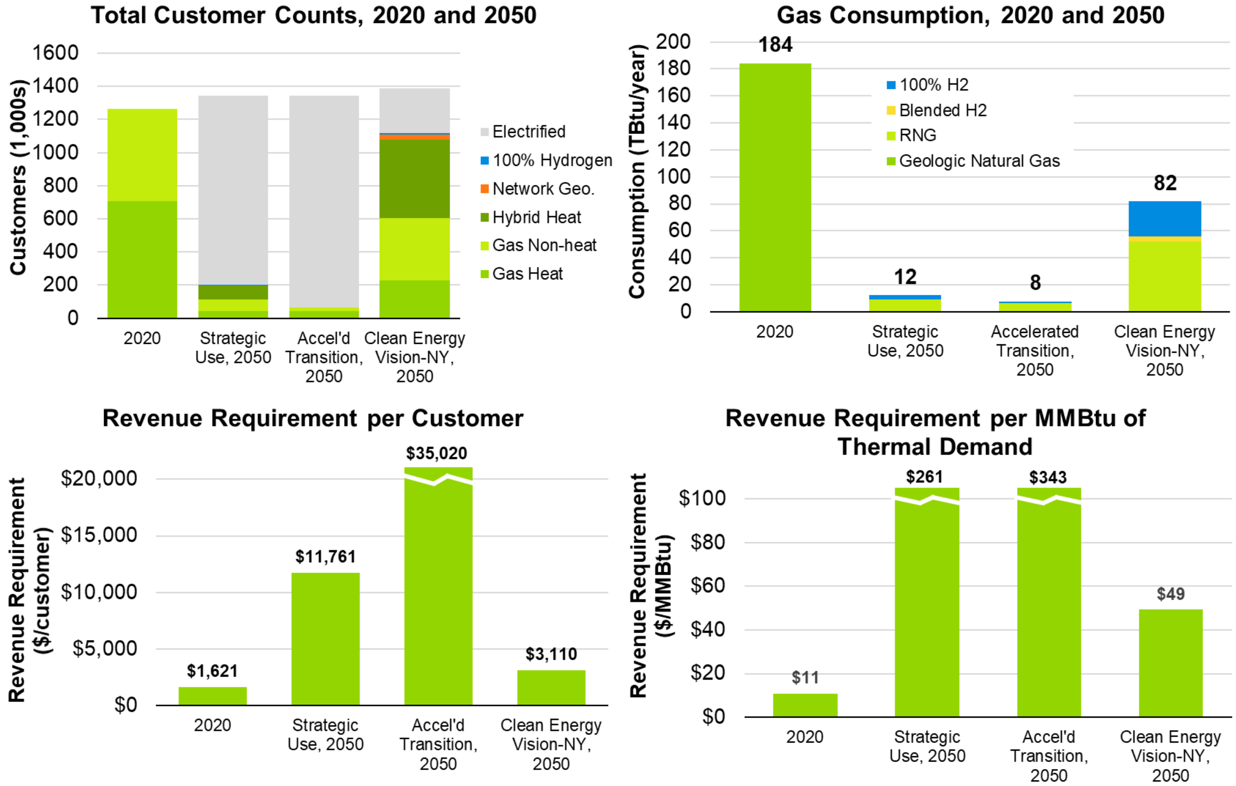


Note: Annual revenue requirement, as described in Section 3.7.2, divided by total thermal customer count and total delivered energy. Inflation adjusted (2020 dollars).

Source: Guidehouse analysis

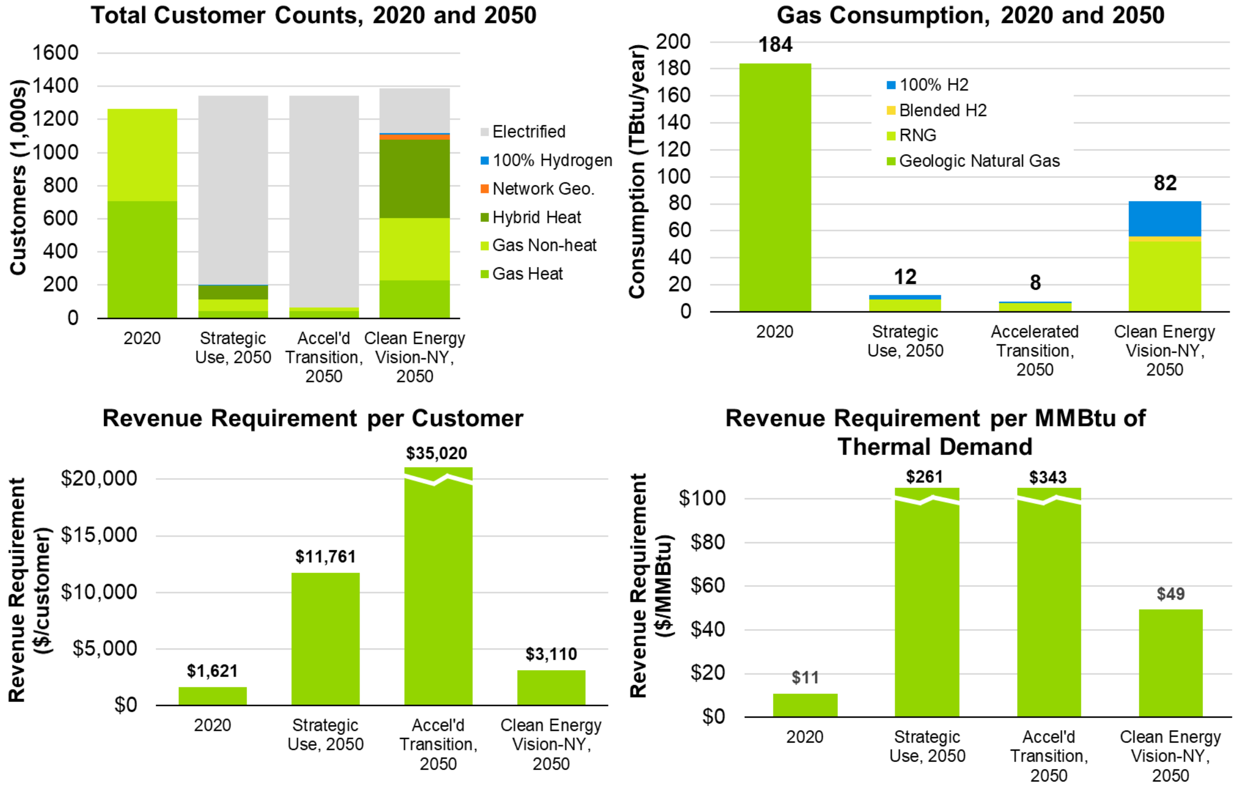
[24] Figures present the annual revenue requirement, as described in Section 3.7.2, divided by total thermal customer count and total delivered energy. Inflation adjusted (2020 dollars). These figures represent a projection of unitized thermal energy network costs under the current regulatory environment – they do not reflect any potential changes to depreciation accounting for thermal utilities in New York State or any other policies and targeted approaches to mitigate long-term affordability challenges. These values also do not assume any cost sharing across energy systems (i.e., the denominators only include thermal system participants and demand in each year).

Figure ES-12. Summary Findings for KEDNY Operating Company



Source: Guidehouse analysis

Figure ES-13. Summary Findings for KEDLI Operating Company



Source: Guidehouse analysis

The charts of customer counts show that in the Integration Analysis scenarios, National Grid customer counts decline quickly and few gas customers would remain on National Grid's networks in 2050. In contrast, the CEV.NY scenario projects a slower rate of decline in customer counts, since many customers would keep their gas connections when they transition to a hybrid heating system.

Pathway Challenges, Risks, and Options to Address

Many challenges will need to be addressed under all scenarios to achieve the scale of transformation implied by CLCPA targets. These challenges, and potential options to address them, are summarized below.

Table ES-5. Challenges and Options to Address Challenges

	Challenge / Risk	Options to Address
Demand-Side Feasibility	- Pace of customer heating equipment turnover versus pace of necessary heating equipment adoption - Barriers to building shell and efficiency installation - Customer willingness/ability to electrify Limitations on supply chain & HVAC workforce	- **Coordinated, geotargeted customer programs** (e.g., demand-side management and heat electrification) - Increased funding of programs to support **building envelope improvements** and adoption of **heat pump technologies,** including government and utility-sponsored **customer incentive programs** - **Workforce training programs**
Supply Side Feasibility	- Siting, permitting, and construction of new electric renewable generation, transmission, and distribution facilities - Pace of necessary expansion of electric transmission, distribution, and storage - Limitations on supply chain & power sector workforce	- **Address siting and permitting challenges** that may be driven by local, state, or federal restrictions or requirements - **Regional planning and coordination** for large transmission projects that cross state or international borders - Accelerate **funding, programs** to support clean energy workforce development
Customer Impacts / Affordability / Equity	- Upfront cost of efficiency and heating equipment upgrades - Increased cost of space heating bills in the short-term for electric heating customers, and in the long-term for thermal customers - Disproportionate impact on low-income customers - Equity and compounding challenges	- **Modified depreciation approaches** to advance recovery and balance near and long-term affordability - Longer-term **socialization of gas network costs** (e.g., electric utility-funded exit fee) - Development of **energy transition equity programs**
Energy System Considerations	- Enhanced coordination across energy systems - Avoidance of gas network costs requires targeted electrification - Procurement of renewable fuels - Legal obligations and regulatory coordination	- **Pilot coordinated gas/electric planning** to assess opportunities to avoid costs - **Clean fuel standard** for thermal energy service to gas distribution customers that includes low-carbon or carbon-free resources (RNG, green hydrogen, networked geothermal) - Broadening of **procurement standards** to include renewable fuels and enable long-term contracting to support project development - **Rate restructuring** to better align recovery of fixed, volumetric costs - Regulatory changes to encourage alternatives to gas system - Alignment of demand-side management and electrification incentives with expected benefit
Technology Readiness and Scalability	- Regulatory and market acceptance of newer technologies (e.g., RNG, hydrogen) - Feasibility of deployment and coordination for network geothermal projects - Scalability of present and future commercial technologies	- Fund and deploy **technology demonstrations and pilots**, leveraging federal funding opportunities where possible - Clarify **utility role** in delivering RNG

Source: Guidehouse

Next Steps for National Grid

Based on this analysis, Guidehouse has organized potential next steps for National Grid into four categories: affordability, infrastructure, technology and workforce, and demand reduction.

Affordability and Equity

- Continue to participate in the development of energy transition equity programs, including income-based and community-based incentives and geotargeted demand-side management programs to meet and exceed the CLCPA's requirement that at least 35% of benefits of clean energy investments accrue to disadvantaged communities.
- Consider how infrastructure investments might be sequenced to prioritize delivery of benefits to disadvantaged communities.
- Continue to explore modified depreciation approaches to advance recovery and balance near and long-term affordability.

Infrastructure

- Develop a comprehensive strategy for leak-prone pipe replacement that prioritizes the safety and emissions benefits from near-term pipe replacements, while identifying opportunities to avoid infrastructure investment where feasible.
- Support development of in-state RNG production, leveraging federal funding opportunities where possible.
- Initiate planning for the development of hydrogen infrastructure, starting with a planning study to identify the inter-regional infrastructure requirements, leveraging federal funding opportunities where possible
- Develop community scale network geothermal systems to avoid replacement of leak prone pipe and reduce peak energy demand.

Technology and Workforce

- Fund and deploy technology demonstrations and pilots for networked geothermal systems, leveraging federal funding where possible.
- Fund and participate in research exploring hydrogen blending in distribution networks, to better understand leakage risks and mitigation strategies, and monitor other hydrogen blending studies designed to test the safety and operational impacts on the gas system, appliances, and local air quality.[25]
- Continue workforce skill development across the clean energy economy which includes, HVAC, energy efficiency, network geothermal, renewable natural gas, hydrogen, utility scale solar, offshore wind, transportation electrification, among others.

Demand Reduction

- Expand energy efficiency, demand response, and customer incentive programs, and assist customer with accessing federal incentives, while making necessary technology investments to enable the success of these programs.

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[25] CPUC Acts To Advance Understanding of Hydrogen's Role As Decarbonization Strategy. **https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-acts-to-advance-understanding-of-hydrogen-role-as-decarbonization-strategy**.

- Expand customer education programs to improve awareness of technologies like hybrid heating and networked geothermal.
- Continue to support the development of workforce training programs to meet a growing need for a skilled and expanded energy efficiency and clean energy workforce.
- Explore innovative financing mechanisms and other new program offerings to complement energy efficiency rebates
- Continue to explore non-pipe alternatives on LPP segments and to solve localized gas system constraints.

Conclusion

The study revealed that the energy transition will be a significant undertaking but finds that a diversified approach that continues to utilize the gas network to support decarbonization is less costly than approaches that prioritize full electrification and gas network decommissioning. A large amount of investment will be needed to extend and upgrade New York's energy system, to retrofit customer buildings, and to replace energy consuming appliances. Compared to the Integration Analysis scenarios, the analysis shows lower total NY State system costs for the CEV.NY scenario due to more diverse investment across sectors and later in time.

Intervention will be needed to maintain reasonable gas utility rates for customers**.** Under the current regulatory environment, with no cost sharing across energy systems, unitized thermal system costs begin to grow significantly starting around 2040. If the energy transition described in the findings above is not accompanied by a regulatory transition, then gas utilities' normalized revenue requirement per customer is projected to increase at least threefold by 2045.

A further challenge for achieving a fair and equitable energy transition is recognition that, absent policy and regulatory intervention, the burden of energy transition costs will likely have disproportionate impacts on customers who remain on the gas distribution system. Without policies and measures to assist low-income and DACs with the energy transition, these customers are more likely to be low-income and households in disadvantaged communities that, barring regulatory intervention, will be left to pay higher rates for gas system maintenance due to fewer customers on the system. Modified depreciation approaches coupled with customer incentives, energy equity programs, and other interventions could ease the transition costs for low- and moderate-income customers.

Many challenges will need to be addressed to achieve CLCPA targets. This study discusses some of those challenges and potential options to address them. Policymakers and regulators in New York will need to consider these issues and take appropriate steps to ensure the continued financial health of utilities essential to the public good while also balancing customer cost considerations, including fair and equitable cost recovery and allocation.

1. Introduction

1.1 Study Background

On July 18, 2019, New York State signed the Climate Leadership Community Protection Act (CLCPA or Climate Act) into law, which mandates that New York State reduce its economy-wide greenhouse gas (GHG) emissions by 40% by 2030 and at least 85% by 2050 from 1990 emissions levels. At the time, the Climate Act was the most ambitious climate legislation that a U.S. state has ever passed, and its implementation will require a transformation of the state's energy systems, particularly for the state's gas utilities.

In the August 2021 New York Public Service Commission (Commission) order adopting[26] the Joint Proposal (Downstate Rate Case Order), which established a three-year rate settlement for National Grid's Downstate New York gas distribution companies, The Brooklyn Union Gas Company d/b/a National Grid NY (KEDNY) and KeySpan East Gas Corporation d/b/a National Grid (KEDLI) (collectively called the Downstate Companies), the Commission stipulated that "… the [Downstate Companies will complete a study evaluating how their businesses may evolve to support the emission reduction and renewable energy goals of the CLCPA and Local Law 97 (the CLCPA Study)."[27] The order requires that the CLCPA Study be completed by the end of Rate Year 3 (March 31, 2023). Additionally, the Downstate Rate Case Order notes the study should:

> "analyze the scale, timing, costs, and customer bill impacts of achieving significant, quantifiable reductions in carbon emissions from the use of gas delivered in their service territories and the projects and programs needed to achieve the CLCPA's specific decarbonization goals";
>
> "incorporate and respond to any findings or guidance of the New York State Climate Action Council"; and
>
> "Identify potential barriers to achieving the targeted carbon emissions reductions and recommended solutions."

On January 20, 2022, a similar CLCPA Study requirement was included in the Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements in Cases 20-E-0380 and 20-G-0381[28] (Upstate Rate Case Order) for Niagara Mohawk Power Corporation d/b/a National Grid (NMPC or Upstate Company). In addition to the requirements included in the Downstate Rate Case Order, the Upstate Rate Case Order notes that the CLCPA Study should prioritize emissions reductions in disadvantaged communities.

In addition to the CLCPA Study, both the Downstate Rate Case Order and the Upstate Rate Case Order required a Depreciation Study be completed at least three months prior to the next base rate filings. The Deprecation Study will evaluate how climate laws and policies could impact average service lives, depreciation rates, customer bills and examine the best survivor curve to inform the next rate filings. In addition, under the Gas Planning Proceeding (20-G-

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[26] New York Public Service Commission *Order Approving Joint Proposal, As Modified, and Imposing Additional Requirements,* issued and effective August 12, 2021, Case 19-G-0309 and Case 19-G-0310 ("Downstate Order").
[27] Downstate Order at p. 173.
[28] New York Public Service Commission. Order Adopting Terms of Join Proposal, Establishing Rate Plans and Reporting Requirements. Effective January 20, 2022. Case 20-E-0380, 20-G-0381, 19-M-0133.

0131), the Companies were required to complete a similar analysis, which was filed on November 8, 2022.[29,30]

1.1.1 Study Objectives

The objectives of this CLCPA study were to address the following questions:

- What is the needed **infrastructure and investment** for each of three scenarios that achieve New York's GHG reduction goals (i.e., 40% reduction by 2030 and 85% reduction by 2050) and local climate objectives (e.g., NYC Local Law 97)?

- How could implementation of these scenarios **financially impact National Grid's customers**, including those in disadvantaged communities?

- What are the **potential challenges, risks, and barriers** to achieving the CLCPA targets and what are **potential options to address those challenges**?

To achieve the study objectives, National Grid and Guidehouse identified three scenarios for needed infrastructure and investment and jointly agreed on key assumptions with engagement from stakeholders, which is described in Section 1.2. Guidehouse used its Low Carbon Pathways tool to estimate necessary investment in electric system (generation, transmission, distribution), natural gas system, hydrogen, and customer heating investments. The analytical methodology is detailed in Section 2.

1.2 Stakeholder Engagement

The Upstate and Downstate Rate Case Orders stated that parties will have the opportunity to provide input on the scope of the CLCPA Study, to review the draft study, and to provide feedback on the final report before it is published.

To enable public input into the study scope, modeling assumptions, and outputs, and to ensure that important issues could be addressed in a public forum and in the CLCPA Study reports, National Grid held four virtual stakeholder meeting sessions, spread throughout the duration of the study and report process.[31]

Meeting materials were shared at least five days prior to each stakeholder session. In addition to providing feedback during the stakeholder sessions, parties had the opportunity to provide

[29] National Grid Depreciation Study: Potential Impacts of Climate Change Policies and Laws. **https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2F3DC718-F064-4E80-8AA2-0922DDBD9B23}**

[30] There are different underlying assumptions for this CLCPA Study and the Depreciation Study.

[31] The first set of stakeholder meetings for Upstate and Downstate New York were held on June 13, 2022 and presented the scope of the study. The second stakeholder meeting was held on August 9, 2022 and reviewed the modeling assumptions and inputs. The third stakeholder meeting was held on November 28, 2022 and reviewed the draft modeling outputs of the study. The fourth stakeholder meeting was held on January 9, 2023 to discuss the draft CLCPA reports and hear stakeholder feedback before they are finalized and published (draft reports shared prior). Due to overlapping content and the two regions' interested parties, National Grid held the second through fourth stakeholder meetings as joint sessions. The CLCPA Study stakeholder meeting materials are available on National Grid's webpage at: **https://www.nationalgridus.com/climate-change-study**

written comments after the stakeholder sessions. Subsequent stakeholder meeting sessions included National Grid and Guidehouse's response to key stakeholder feedback.

Stakeholder feedback and commentary helped guide changes to the scope of the CLCPA study. The team made several changes to the study and the draft report based on stakeholders' comments.[32]

Table 1-1. Stakeholder Meetings

Meeting	Focus	Date & Time	Presentation Slides
Stakeholder Meeting #1	Scoping	Downstate – July 13, 2022 10 a.m. ET Upstate – July 13, 2022 2 p.m. ET	**Guidehouse Slides** **National Grid Slides**
Stakeholder Meeting #2	Modeling Inputs and Assumptions	August 9, 2022 10 a.m. ET	**Slides**
Stakeholder Meeting #3	Modeling Outputs	November 28, 2022 2 p.m. ET	**Slides**
Stakeholder Meeting #4	Draft Report	January 9, 2023 2 p.m. ET	TBA

Source: Guidehouse

1.3 National Grid New York's Natural Gas System

National Grid provides gas service in portions of Upstate and Downstate New York. In Upstate NY (UNY), NMPC provides gas service in portions of Jefferson, Oswego, Onondaga, Madison, Oneida, Herkimer, Fulton, Montgomery, Warren, Saratoga, Schenectady, Albany, Washington, Rensselaer, and Columbia counties. As of 2021, NMPC serves approximately 600,000 gas customers via 8,900 miles of gas mains.[33] In Downstate New York (DNY), KEDNY operates in New York City in the counties of Staten Island, Brooklyn, and parts of Queens, and KEDLI operates across Long Island (Nassau and Suffolk counties and the Rockaway Peninsula in Queens). KEDNY and KEDLI provide service to approximately 1.2 million and 590,000 customers,[34] respectively, totaling nearly 1.8 million customers. As of 2021, National Grid's Downstate gas business encompassed approximately 12,600 miles of gas mains.[35]

National Grid currently supports New York in reducing GHG emissions from the gas network by reducing gas demand and decarbonizing the gas supply. The following sections describe National Grid's efforts in these two areas.

[32] Changes made in response to stakeholder feedback include the following: emissions costs were cited to a more recent NYISO source, anaerobic digestion costs were aligned with ICF AGF 2019 report, battery storage types were aligned with ABT 2022 classifications, GSHP efficiency values were aligned with NYSERDA Heat Pump Study, cost and efficiency assumptions were added for hydrogen boilers. This list is not exhaustive but covers the main categories that incorporated stakeholder feedback.

[33] US Department of Transportation Pipeline and Hazardous Materials Safety Administration. Gas Distribution Annual Data 2010 to present.

[34] New York Public Service Commission. Order Approving Joint Proposal, As Modified, and Imposing Additional Requirements. Issued and Effective August 12, 2021. Case 19-G-0309, 19-G-0310, 18-M-0270

[35] US Department of Transportation Pipeline and Hazardous Materials Safety Administration. Gas Distribution Annual Data 2010 to present.

1.3.1 Reducing Gas Demand

- National Grid's energy efficiency programs reduced over 1,800,000 MMBtu of gas that would otherwise have been consumed by NY customers in 2021 and in 2022; the American Council for an Energy Efficient Economy (ACEEE) ranked NY's energy efficiency program 3rd in the U.S.[36]
- In September 2022, National Grid received an award of $1M from the U.S. Department of Energy to partially fund a pilot in DNY to test gas demand response using hybrid gas-electric heating systems.
- In October 2022, National Grid proposed up to four pilots in support of the Utility Thermal Energy Network and Jobs Act. The pilots will explore networked thermal energy opportunities across customers classes, densities, and ownership models[37].
- To address rapidly-growing customer heating demand in the Downstate New York region, National Grid has developed alternatives to new infrastructure such as launching a building weatherization program (i.e., insulation), non-pipeline alternatives, and industry-leading gas demand response programs to reduce customers' peak period gas use (which also recently expanded to the UNY region), among other potential solutions.
- National Grid continues to collaborate with the local electric distribution companies to encourage customers seeking to connect to the gas system to instead consider electric heat pumps.

1.3.2 Decarbonizing the Gas Supply

- National Grid is working with NYC DEP and Waste Management on the Newtown Creek Biogas Facility, which will inject up to 760 dth/day into the gas distribution system when operating at full capacity.
- Through a Request for Information in April 2022, National Grid identified potential Renewable natural gas (RNG) and hydrogen (H2) projects throughout North America that, if constructed, could deliver approximately 33 tBtu of RNG to customers.[38]
- National Grid is partnering with the Town of Hempstead, NY to develop a clean hydrogen facility that will blend hydrogen that is created from renewable energy into an isolated portion of the gas distribution system.[39]
- National Grid is a partner to NYSERDA in the development of the Northeast Hydrogen Hub proposal.[40]

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[36] ACEEE, 2022 State Energy Efficiency Scorecard New York. https://www.aceee.org/sites/default/files/pdfs/State_Scorecard/2022/one-pagers/New_York.pdf

[37] New York DPS Case 22-M-0429, https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=22-M-0429&CaseSearch=Search

[38] National Grid, 2022. https://www.nationalgridus.com/News/2022/08/National-Grid-8217-s-first-of-its-kind-renewable-energy-RFI-validates-a-fossil-free-energy-strategy-for-the-Northeast/

[39] National Grid, 2021. https://www.nationalgridus.com/News/2021/12/National-Grid-and-Town-of-Hempstead-to-Develop-One-of-the-First-Green-Hydrogen-Blending-Projects-in-the-Country/

[40] NYSERDA, 2022. https://www.nyserda.ny.gov/About/Newsroom/2022-Announcements/2022-03-24-Governor-Hochul-Announces-Multi-State-Agreement-on-Hydrogen

- National Grid continues to collaborate with peer utilities, GTI Energy, Stony Brook University, and other research organizations on hydrogen safety and material and appliance compatibility research.
- National Grid has recently begun testing tools for the integrated modeling of electric and gas networks.[41]

1.4 Policy Context

This section describes the policy landscape at the state, federal, and local levels relevant for this study.

1.4.1 New York Policy Context

New York State has set several clean energy and decarbonization policy targets. All current targets, as identified in Table 1-2, are assumed to be met across all three modeled scenarios in this study.

Table 1-2. New York State Policy Targets

Legislation	Policy Target	Goal
Climate Leadership and Community Protection Act	Offshore Wind Deployment Target	9 GW of offshore wind built by 2035
	Battery Storage Deployment Target	3 GW of battery storage built by 2030
	Clean Energy Standard	70% renewable electricity by 2030
	Zero-Emission Electricity	100% zero-emission electricity by 2040
	Economy-wide GHG Emissions	40% below 1990 levels by 2030
		85% below 1990 levels by 2050
New York State Energy Research and Development Authority (NYSERDA) 2022 NY-Sun Initiative	Distributed Solar Deployment Target	10 GW of distributed solar built by 2030

Source: CLCPA[42] and NYSERDA 2022 NY-Sun Initiative[43]

1.4.1.1 CLCPA

In July 2019, New York State enacted into law the Climate Leadership and Community Protection Act[44] that established economy-wide GHG reduction mandates of 40% below 1990 levels by 2030 and net zero emissions by 2050 (85% reductions plus emission offsets).

The CLCPA also established several statewide energy requirements including 100% emissions-free electricity by 2040 (with the interim goal of 70% renewable electricity by 2030); the installation of 9,000 MW of offshore wind by 2035, 6,000 MW of solar by 2025, and 3,000 MW of

[41] BusinessWire, 2022. https://www.businesswire.com/news/home/20221129005030/en/National-Grid-licenses-encoord%E2%80%99s-SAInt-software-for-integrated-planning

[42] "NY State Senate Bill S6599". NY State Senate. https://www.nysenate.gov/legislation/bills/2019/s6599

[43] Governor Hochul Announces Approval of New Framework to Achieve at Least Ten Gigawatts of Distributed Solar by 2030 – NYSERDA

[44] "NY State Senate Bill S6599". NY State Senate. https://www.nysenate.gov/legislation/bills/2019/s6599

energy storage by 2030; and a statewide energy efficiency goal of 185 trillion BTUs below the state's 2025 energy use forecast.

After the passage of the CLCPA, in early 2022, the New York Public Service Commission approved a roadmap for a higher solar goal of 10 GW by 2030 since the state was close to meeting the 2025 goal. The 10 GW goal also includes 1,600 MW for disadvantaged communities and low-to-moderate income households, 450 MW in the ConEdison service territory, and 560 MW through the Long Island Power Authority. The CLCPA requires that at least thirty-five, and preferably forty, percent of overall benefits from clean energy and energy efficiency spending accrue to disadvantaged communities.

In addition, under the CLCPA, the Department of Environmental Conservation (DEC) is responsible for enforcing the emission reduction targets and required to report on statewide emissions on an annual basis.

1.4.1.2 Climate Action Council (CAC)

The CLCPA created the Climate Action Council (CAC), a 22-member body comprised of representatives from state agencies and council appointees.[45] The CAC is responsible for preparing a scoping plan to achieve the requirements of the CLCPA within 2 years of the legislation passing and every 5 years thereafter.

The CAC released the Draft Scoping Plan in December of 2021; the public comment period opened on January 1 and closed on July 1, 2022. The CAC approved the final Scoping Plan in December of 2022.[46]

The Draft Scoping Plan proposed several sector-specific policies and regulations that target emissions from transportation, electricity, industry, buildings, agriculture and forestry, and waste. The plan also proposed the introduction of a market-based economy-wide emissions policy, such as a carbon price or cap-and-invest program, to achieve the emissions reduction goals of the CLCPA.

As part of the Scoping Plan, the CAC included a technical Integration Analysis completed by Energy and Environmental Economics (E3) that modeled policy scenarios to predict gross GHG emissions relative to a reference case. The study, which includes four scenarios with varying approaches to enabling deep decarbonization, found that achieving New York's emissions goals is technically possible by 2050 and that pursuing those avenues would lead to net societal benefits.

The final Scoping Plan does not identify specific emissions limits for the buildings sector. However, it does identify key focus areas and recommendations for the buildings sector and gas transition. Key discussion elements in the final Scoping Plan with particular relevance to this analysis include:

- Recognition that electrification and energy efficiency will be essential to decarbonization of the buildings sector. The Scoping Plan includes a vision that by 2050, 85% of residential and commercial buildings are electrified "with a diverse mix of energy efficient

[45] New York Climate Action Council, **https://climate.ny.gov/Our-Climate-Act/Climate-Action-Council**
[46] New York's Scoping Plan, **https://climate.ny.gov/resources/scoping-plan/**

heat pump technologies, and thermal energy networks,"[47] and recognizes the value of using backup heat sources, particularly in cold areas or to mitigate potential electric capacity constraints.[48]

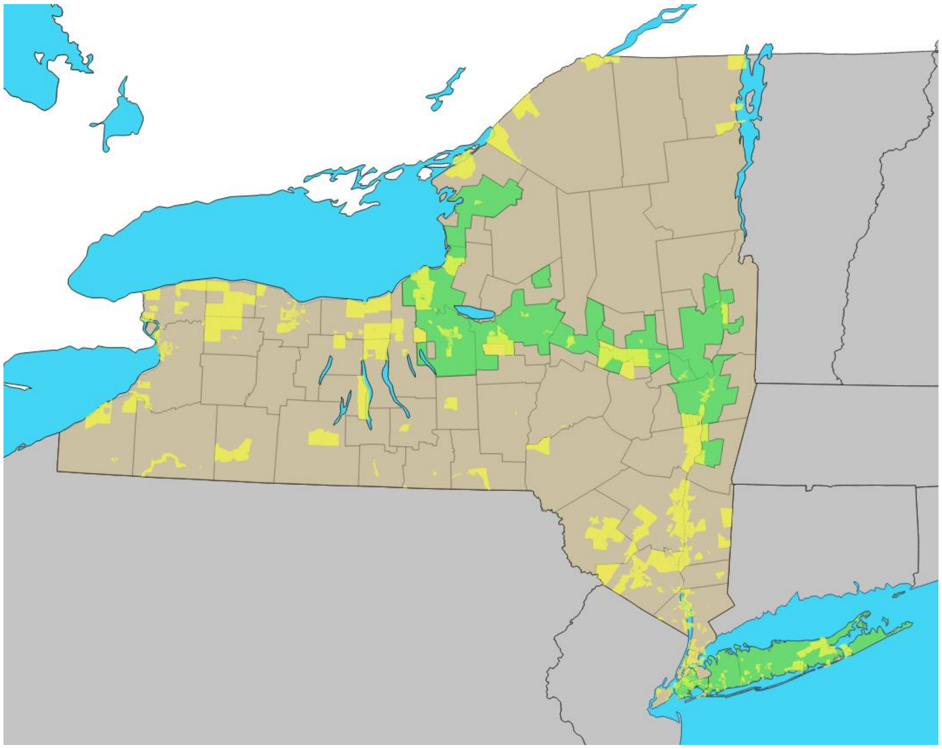
- Recognition that achieving emissions limits will "entail a substantial reduction of fossil natural gas use and strategic downsizing and decarbonization of the gas system."[49]
- Recognition of the strategic role that renewable fuels may play "to meet customer needs for space heating or process use where electrification is not yet feasible or to decarbonize the gas system as it transitions."[50]
- Recognition that the pace of gas network transition will depend on the pace of customer adoption of alternative heating technologies, and that gas utilities retain an obligation to provide safe and reliable service.[51]

1.4.1.3 Climate Justice Working Group & Disadvantaged Communities

The Climate Justice Working Group (CJWG) was established by the CLCPA[52] and tasked with establishing criteria for identifying disadvantaged communities (DAC).[53] The CLCPA requires that at least 35% and preferably 40% of direct state resources be allocated to DACs through investments, workforce development, pollution reduction, and development projects. The CJWG published draft criteria for identifying DACs in March 2022 that included 45-indicators including environmental exposures, climate change risks, race, income, health vulnerabilities, and pollution characteristics. Applying these draft criteria yielded preliminary identification of DACs throughout the state, which are shown overlaid with National Grid gas service territory in Figure 1-1 below. Note that these are draft DACs; the CJWG has not yet finalized DAC identification.

[47] Scoping Plan, page 180.
[48] Scoping Plan, page 361.
[49] Scoping Plan, page 350.
[50] Scoping Plan, page 351.
[51] Scoping Plan, page 353.
[52] Climate Justice Working Group, **https://climate.ny.gov/Our-Climate-Act/Climate-Justice-Working-Group**
[53] "Disadvantaged communities" are defined in the CLCPA as communities that bear burdens of negative public health effects, environmental pollution, impacts of climate change, and possess certain socioeconomic criteria, or comprise high-concentrations of low- and moderate- income households.

Figure 1-1. New York State Disadvantaged Communities



Note: Yellow indicates March 2022 Draft DACs, and green indicates National Grid gas service territories.

Source: March 2022 draft DAC shapefile available at: ***https://data.ny.gov/Energy-Environment/Draft-Disadvantaged-Communities-DAC-2021/xj7e-q8ja***

As shown in the map and Table 1-3 below, National Grid's gas service territories include draft DACs. The KEDNY territory is especially coincident with draft DAC territories, holding over a quarter of the state's households which fall within a DAC. Note that the totals below do not include low-income households not located within the draft DAC geographies.

Table 1-3. Percent of Households within Draft DACs

Region	Percent of Regional Households within DAC	Percent of NY DAC Households within Region
NMPC Gas	26%	8%
KEDNY	40%	27%
KEDLI	12%	4%
New York State Total	36%	100%

Note: Based on intersection of draft DAC data and National Grid gas service territories. This does not include low-income households not located within the draft DAC geographies.

Source: March 2022 draft DAC shapefile available at: ***https://data.ny.gov/Energy-Environment/Draft-Disadvantaged-Communities-DAC-2021/xj7e-q8ja***

1.4.1.4 Networked Geothermal

New York adopted the Utility Thermal Energy Network and Jobs Act (S9422) on July 5, 2022, which allows New York State utilities to own and operate thermal energy networks.[54] These

[54] "NY State Senate Bill S9422". NY State Senate. **https://www.nysenate.gov/legislation/bills/2021/S9422**

underground networks will enable multiple buildings to share thermal energy sources. Shared thermal energy networks are expected to improve energy efficiency, reduce GHG emissions, enable buildings to utilize thermal energy resources including geothermal heat pumps, and lower energy costs.

The Law directs the Commission to promote the development of these networks. This includes directing utilities in the state to create pilot projects and develop a regulatory framework for deploying thermal energy networks. The Commission is required to initiate proceedings by October 2022 and promulgate regulations by July 2024.

The Commission initiated such a proceeding to Implement the Utility Thermal Energy Network and Jobs Act in September 2022, with New York utilities, including National Grid submitting proposal for thermal network pilots and holding a Technical Conference on December 1, 2022.[55]

1.4.1.5 Energy Efficiency

New York State has a longstanding history of promoting energy efficiency. In 2008, the Commission accelerated efficiency efforts by creating the Energy Efficiency Portfolio Standard, which required that the state reduce electricity consumption by 15% relative to forecasts by the year 2015. In 2015, the Reforming the Energy Vision Regulatory Proceeding set a goal of a 23% decrease in energy consumption in buildings relative to 2012 levels by 2030.

The most recent energy efficiency target was declared in the Proceeding In the Matter of a Comprehensive Energy Efficiency Initiative (Case 18-M-0084), otherwise referred to as New Efficiency: New York, and thereafter codified in the CLCPA, which includes a statewide energy efficiency target of a reduction of 185 trillion BTUs in energy savings from buildings and industrial facilities below the 2025 energy use forecast. New Efficiency: New York energy efficiency and building electrification programs are currently authorized through 2025. An interim review is in progress and may result in program changes in programs and an extension beyond 2025.

1.4.2 Recent Federal Policy Context

The federal government recently enacted both the Bipartisan Infrastructure Law and the Inflation Reduction Act. These two pieces of legislation will broadly influence New York's electric and gas sectors and customers.

1.4.2.1 Bipartisan Infrastructure Law

In November 2021, Congress passed and President Biden signed the Bipartisan Infrastructure Law, which allocates $1.2 trillion in investment including $550 billion in new spending dedicated to infrastructure upgrades to America's roads, bridges, railways, water infrastructure, and energy infrastructure, among others.

The law includes investments relevant to meeting the goals of the CLCPA, including $8 billion to develop regional clean hydrogen hubs, $7.5 billion in funding for electric vehicle charging stations, $65 billion for transmission expansion, $3.2 billion to increase Weatherization

[55] **https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=68607&MNO=22-M-0429**

Assistance Program funding, and $50 billion for improving resilience of infrastructure for climate change and extreme weather.

1.4.2.2 Inflation Reduction Act (IRA)

On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA) into law, which will provide new incentives for clean energy and energy efficiency investments and programs.

The IRA provides incentives in the form of tax credits to several clean energy technologies, including traditional renewables, electric vehicles, biodiesel, renewable natural gas, carbon capture, hydrogen, and energy efficiency, among others.

The IRA is expected to have widespread impacts on the deployment of clean energy resources across the energy system. While the timeline of the IRA's passage did not provide sufficient time to conduct a comprehensive revision of the modeling used in this study, the potential cost impacts of relevant provisions were evaluated qualitatively. The forecast impacts of IRA provisions on scenario modeling results are listed below in Table 1-4.

Table 1-4. Impacts of IRA on Scenario Model Outputs

Topics (IRA Section)	Difference Between Scenarios	Rationale
Renewable Electric Generation (13101-13103)	Very Small	All scenarios project similar renewable development on a similar timeline (~45GW by 2030, ~135 GW by 2050). CEV.NY has slight difference in capacity mix.
Biogas Production (13102)	Small, favoring CEV.NY	CEV.NY scenario assumes greater deployment of incentive-eligible RNG. However, CEV.NY assumes most development of RNG happens after incentives sunset in 2025.
Carbon Capture (13104) Nuclear Power (13105) Vehicles (13401-04)	None	All scenarios have limited CCS deployment, have the same timeline for nuclear generation, and use similar assumptions re: vehicle fleet conversion.
Hydrogen Production (13204)	Large, favoring CEV.NY	CEV.NY deploys a much larger amount of in-state H2 generation than Integration Analysis scenarios, and deployment is all green H2, expected to qualify for high incentives.
Building Energy Efficiency (13301,13303)	None	Scenarios have identical assumptions re: building efficiency improvements.
Building Heating & Hot Water Equipment (13302)	Small, favoring CAC	Tax credits will reduce customer cost of equipment upgrades. Integration Analysis scenarios assume 10-15% higher adoption of heat pump equipment compared to CEV.NY scenario.
Residential Efficiency & Electrification Rebates (50121-23)	Small, favoring CAC	Rebates will reduce customer cost of building & equipment upgrades. Scenarios have similar assumptions re: efficiency & equipment, but Integration Analysis scenarios have slightly higher heat pump adoption. The impact of federal rebates will depend on state-level implementation approach.
Methane Emissions (60113)	Unclear – Likely small, favoring CAC	Could increase commodity cost of NG supply to account for methane emissions fees. All scenarios assume some continued gas use, and all scenarios cease fossil fuel use. CEV.NY scenario may be more impacted in interim years, prior to transition to RNG. Magnitude depends on upstream emissions and interventions to reduce them.

Source: Guidehouse analysis

As noted in Table 1-4, the IRA's tax credits for renewable energy production and hydrogen production would likely impact scenarios differently. The renewable energy credits (in particular, the extension and expansion of the production and investment tax credits) would likely decrease the costs of most eligible technologies, requiring the model revision to include lower cost assumptions for these resources. However, there are uncertainties around what percentage of the renewable projects would qualify for the bonus credits available for projects that meet prevailing wage and apprenticeship requirements, domestic content requirements, or development in an energy community.

The same uncertainty is true for assumptions regarding hydrogen production. The production tax credit (which credits hydrogen facilities for every kilogram of hydrogen produced) is expected to lower the costs of hydrogen production. Other provisions that could influence the costs assumed in modeling would be the increase in incentives for energy efficiency and the extension of the 45Q tax credit for carbon capture facilities.

1.4.3 Local and Regional Policies

New York City Local Law 97 passed in April 2019 and established a building performance standard for the city. The law establishes emissions intensity limits (total building emissions by square footage) for buildings greater than 25,000 gross square feet (or two or more buildings on the same lot or governed by the same board of managers greater than 50,000 gross square feet). By law, covered buildings must comply with emission intensity targets by 2024 and stricter targets by 2030.

The law allows for some flexibility. In addition to reducing emissions through traditional approaches, covered buildings may also use renewable energy credits or carbon offset credits (up to 10% of emissions) for compliance.

New York City also passed Local Law 154 in December 2021 that requires the phase-out of fossil fuels for new construction by requiring new buildings to be all-electric. The compliance schedule varies by building type; low-rise new buildings must comply starting in 2024, while larger buildings and affordable housing have later compliance deadlines; the latest is Jan 1, 2028 for buildings with more than seven stories and at least 50% affordable housing units.

1.4.4 Ongoing Regulatory Proceedings

The are several ongoing regulatory proceedings that are relevant to this study. In particular, these include Cases 20-G-0131, 19-G-0678, and 22-M-0149.

The Proceeding on Motion of the Commission in Regard to Gas Planning Procedures (Case 20-G-0131) considers issues in planning for gas utilities as they face supply constraints, moratoria on new service connections in some areas, and navigate planning under the CLCPA.[56] Since it was initiated in March 2020, in August 2022, National Grid filed a proposal for screening non-pipe alternatives and suitability criteria and the New York gas utilities (Joint LDCs) filed non-pipe alternatives incentive framework. Also, in August 2022 the Joint LDCs provided a report on the 100 foot customer entitlement. In addition, in November 2022, National Grid filed an analysis of the structure of accelerated depreciation and its potential impacts on customers based on the potential impacts of CLCPA targets on gas throughput and customer counts on November 8. 2022. National Grid will file its gas long-term plans under this proceeding in 2024.

Case 19-G-0678, Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and

[56] New York Department of Public Service. Case 20-G-0131. **https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-G-0131**.

KeySpan Gas East Corporation d/b/a National Grid, was initiated to address issues regarding gas customers being denied new service due to supply constraints.[57] The development of a Long-Term Capacity Report, its publication, and incorporation of public input was part of the Settlement. Since the proceeding was initiated in October 2019, the Downstate Companies have filed long-term capacity outlook reports that rely on energy efficiency and demand response programs in addition to gas resources to meet demand.

Case 22-M-0149, the Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act, serves as the forum for tracking policy changes and other advancements made toward meeting the requirements under the CLCPA.[58] These include directive to the utilities to develop a proposal for an annual GHG emissions inventory report, to include GHG emissions from the gas network in all future rate filings, develop a GHG Emissions Reduction Pathways Study Proposal, and to include a description in future rate filings of the programs necessary for achieving the objectives carved out in the pathways study. In December 2022, the New York Joint Utilities provided their proposal for the annual GHG Emissions Inventory Report. In addition, this proceeding will be where the Department of Public Service Staff reports on overall compliance with the CLCPA's requirement that at least 35% of benefits of clean energy investments accrue to disadvantaged communities.

[57] New York Department of Public Service. Case 19-G-0678. **https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-g-0678**.

[58] New York Department of Public Service. Case 22-M-0149. **https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=22-M-0149**.

2. Study Approach

This study used scenario-based analysis to compare three different visions of the future (i.e., scenarios) and to determine the timing, scale, and cost of meeting the requirements and the statewide GHG limits established by the Climate Act. The scenarios in this analysis were defined by assumptions about how residents, buildings, and industries will use energy in the future to meet their needs around transportation, space conditioning, and production of goods. For instance, scenarios were defined by parameters such as the portion of buildings that are partially or fully electrified and the portion of heating loads that will be met by renewable and low-carbon fuels over the course of the study period (2020-2050).

As noted in Section 1.1.1, a primary objective of this analysis was to examine the infrastructure development and investments that would be needed to enable different pathways and scenario outcomes. The analysis modeled the changes to energy demand and energy supply that could occur over time (i.e., the pathways) as NY shifts from current to potential future state energy use scenarios.

The study approach was divided into four phases (see Table 2-1), which are detailed in the following subsections.

Table 2-1. Overview of Study Methodology

Phase 1: Scenario Definition	**Phase 2: Demand Forecasting**
Defined each scenario in terms of assumptions about future energy use patterns and technology adoption trends.	Estimated the end-use demand for different sectors and energy carriers, accounting for the effects of energy efficiency and other demand-side management interventions, electrification, and fuel switching.
Phase 3: Energy System Modeling	**Phase 4: Cost Modeling**
Determined the production capacity and the supply side developments that would be needed to meet energy demand in each scenario, including the development of new energy generation facilities and investments in transmission and distribution infrastructure needed to connect energy supply to demand.	Estimated the demand-side and supply side costs that will be incurred to transition from the current state to the scenario outcome.

Source: Guidehouse

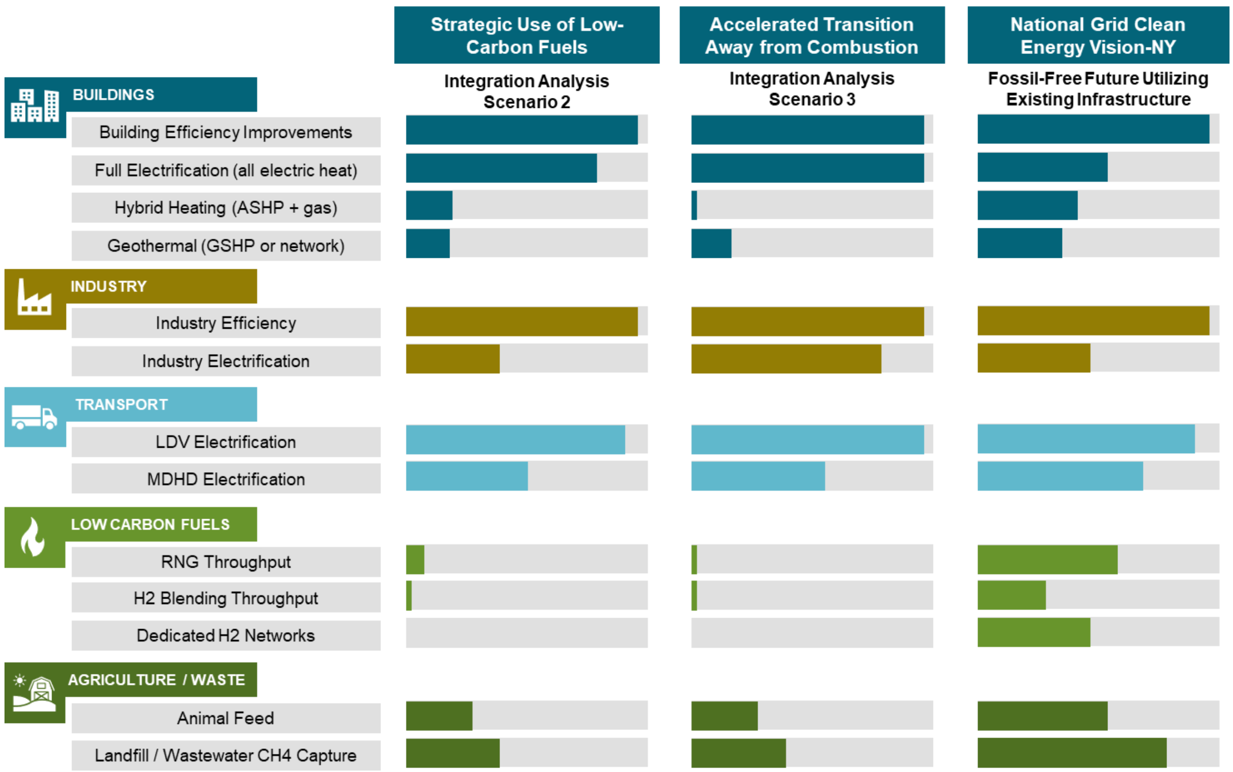
2.1 Scenario Definition

Each of the three scenarios meet the requirements established by New York's Climate Act, including gross GHG emissions limits in 2030 and 2050 and necessary new renewable electricity generation and electricity storage capacity. These three scenarios defined demand and supply constraints for the future energy system. Two scenarios were adapted from the CAC's Integration Analysis: The **Strategic Use of Low-Carbon Fuels** scenario (Integration Analysis Scenario #2) and the **Accelerated Transition Away from Combustion** scenario (Integration Analysis Scenario #3).[59] A third scenario, the **Clean Energy Vision-New York**

[59] NY Climate Action Council (December 2021). Draft Scoping Plan, Appendix G. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scoping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.pdf**

scenario (hereafter, "CEV.NY"), was based on National Grid's April 2022 publication describing a future where existing gas infrastructure supports the delivery of low carbon fuels.[60] The CEV.NY scenario was distinguished from the Integration Analysis scenarios in its assumptions for the buildings sector, for which the CEV.NY scenario assumed higher rates of partial building electrification and a greater role for hydrogen and RNG. For the industry and transportation sectors, the CEV.NY scenario adopted the same assumptions as the Strategic Use of Low-Carbon Fuels scenario.[61]

Figure 2-1. Summary Comparison of Scenarios, by Sector



Source: Guidehouse

The CEV.NY scenario defined separate assumptions for building electrification and equipment conversions in New York City and non-New York City regions, to reflect the unique characteristics of these regions. For example, New York City buildings over 25,000 square feet in area must comply with Local Law 97, which sets emissions intensity limits that become more stringent over time. The CEV.NY scenario assumed a higher portion of homes convert to ground-source heat pumps in non-NYC regions of the state because, due to their lower building density, non-NYC regions generally have more opportunities for siting underground heat exchanger loops.

[60] National Grid (April 2022). "Our clean energy vision: A fossil-free future for cleanly heating homes and businesses." Available at: **https://www.nationalgrid.com/document/146251/download**

[61] The Strategic Use of Low Carbon Fuels scenario assumptions for industrial and transportation sectors align with the strategic pillars of the Clean Energy Vision, in that the scenario assumes the industrial and transportation are decarbonized using a mix of electricity and renewable fuels, and that renewable fuels are used to mitigate growth in peak electric demand.

The scenarios differed by future energy demand mix for the major end-use sectors, both in terms of total energy demand changes and the portfolio of fuels used to meet energy demand. For the CEV.NY scenario, for example, there will be less electricity demand from buildings by 2050 compared to the CAC's Integration Analysis scenarios because the CEV.NY scenario assumes lower adoption of whole-building air-source heat pump (ASHP) technology and that gas-electric hybrid heating systems and networked geothermal heating will play a greater role in decarbonizing building heat.

The scenario parameters also differed by geography according to the different demand profiles and technology mixes that exist today. The applicability and technical feasibility of zero- and low-carbon replacements and the influence of local policies such as NY City's Local Law 97 varied by region. In addition, the more prevalent use of heating oil Upstate will inform the energy profiles of the region and how they can decarbonize. Networked geothermal will be limited to areas where there is relatively close customer proximity, suitable soil characteristics, and pipelaying is not prohibitively expensive (e.g., in a suburb). All of these factors informed the demand forecasts for the regions analyzed in this study.

For the two scenarios from the CAC's Integration Analysis, Guidehouse referenced the extensive assumptions workbooks published by the NY CAC. For the CEV.NY scenario, Guidehouse compiled assumptions based on input from National Grid, a review of modeling assumptions from the CAC Integration Analysis and the Massachusetts 20-80 proceeding, Guidehouse internal expert judgement, and secondary research. Table 2-2 compares the defining parameters of the three scenarios.

Table 2-2. Scenario Assumptions by Demand Sector

<table>
<tr><th>Sector</th><th>Strategic Use of Low-Carbon Fuels (CAC#2)</th><th>Accelerated Transition Away from Combustion (CAC#3)</th><th>Clean Energy Vision-New York (CEV.NY)</th></tr>
<tr><td rowspan="3">Buildings</td><td>92% of residential and commercial buildings are electrified by 2050

Electrification is 70% ASHP, 20% ground-source heat pump (GSHP), and 10% Hybrid heat</td><td>92% of residential and commercial buildings are electrified by 2050

Electrification is 77% ASHP, 23% GSHP, with no hybrid heat</td><td>Networked geothermal serves 4% of NYC and 8% of non-NYC housing units.

20% of non-residential customers convert to 100% hydrogen heat by 2050.

75% of housing units are electrified by 2050, split as:<table><tr><th></th><th>NYC</th><th>Other</th></tr><tr><td>Hybrid</td><td>76%</td><td>48%</td></tr><tr><td>ASHP</td><td>16%</td><td>39%</td></tr><tr><td>GSHP</td><td>8%</td><td>13%</td></tr></table>70% of commercial building space is electrified by 2050, split at 65% hybrid heat, 20% ASHP, and 15% GSHP</td></tr>
<tr><td colspan="3">Building efficiency improvements reduce heating and cooling loads by 31% from 2020 to 2050</td></tr>
<tr><td colspan="2">Remaining non-electric energy demand served by RNG and low-carbon fuels (e.g., biofuel)

No hydrogen blending in pipeline gas</td><td>Remaining gas demand served by RNG/hydrogen blend, increasing to 7% hydrogen (by energy) by 2050</td></tr>
<tr><td rowspan="2">Industry</td><td colspan="3">Industry efficiency improvements reduce annual energy consumption 40% from 2020 to 2050</td></tr>
<tr><td>33% of gas use is electrified by 2050.
Remaining gas use is served by hydrogen.</td><td>83% of gas use is electrified by 2050.
Remaining gas use is served by hydrogen.</td><td>33% of gas use is electrified by 2050.
Remaining gas use is served by hydrogen.</td></tr>
<tr><td rowspan="2">Transport</td><td>By 2050:
LDV stocks are 95% ZEV,
MDHD stock is 77% ZEV</td><td>By 2050:
LDV stocks are 96% ZEV,
MDHD stock is 86% ZEV</td><td>By 2050:
LDV stocks are 95% ZEV,
MDHD stock is 77% ZEV</td></tr>
<tr><td colspan="3">Marine and ports are fully electrified by 2050</td></tr>
<tr><td>Agriculture</td><td colspan="2">Changes to animal feed yield 24% decrease in annual livestock methane emissions from 2020 to 2050</td><td>Changes yield 50% decrease in annual livestock methane emissions from 2020 to 2050</td></tr>
<tr><td rowspan="2">Waste</td><td colspan="2">Methane capture at landfills reduces annual landfill methane emissions by 70% from 2020 to 2050</td><td>Landfill methane emissions reduced 75%, 2020 to 2050</td></tr>
<tr><td colspan="2">Wastewater methane capture reduces annual wastewater methane emissions by 25% from 2020 to 2050</td><td>Wastewater methane emissions reduced 65%, 2020 to 2050</td></tr>
</table>

Source: Guidehouse analysis and NY CAC (December 2021)[62]

2.2 Integration Analysis Scenarios

For the CAC's Integration Analysis, the NY CAC conducted a scenario design planning exercise to develop thematic scenarios designed to meet or exceed the Climate Act's GHG emissions limits in New York. This study analyzed two of the scenarios developed by the CAC, described as follows:

- The **Strategic Use of Low-Carbon Fuels** scenario included the use of bioenergy derived from biogenic waste, agriculture & forest residues, and limited purpose grown biomass, as well as a role for green hydrogen for difficult to electrify applications, and limited use of negative emissions technologies to achieve carbon neutrality in 2050.
- The **Accelerated Transition Away from Combustion** scenario assumed a limited role for bioenergy and hydrogen combustion and accelerated electrification of buildings and transportation, as well as limited use of negative emissions technologies (e.g., direct air capture of carbon dioxide) to achieve carbon neutrality in 2050.

As noted in Table 2-2, both Integration Analysis scenarios assumed a high degree of building electrification, with over 90% of buildings achieving complete electrification including all thermal end uses by 2050. These scenarios assumed that over 83% of residential buildings and over 90% of commercial buildings disconnect from the natural gas distribution network by 2050. The CAC's Draft Scoping Plan provides more details regarding these two scenarios.[62]

2.3 National Grid Clean Energy Vision-New York

The National Grid CEV.NY scenario emphasized the use of low-carbon and renewable fuels, such as green hydrogen and renewable natural gas, in conjunction with electrification to meet the Climate Act's GHG emissions requirements. To mitigate peak electric demand, the CEV.NY scenario relied on existing gas infrastructure to deliver low-carbon and carbon-neutral gases. Compared to the Integration Analysis scenarios, the CEV.NY scenario assumed a larger portion of customers transition from gas heating to hybrid heating systems, which combine an electric ASHP with a gas-fired heating system that can meet heating needs during cold periods when heat pumps are less efficient.

The CEV.NY scenario assumptions were based on the four strategic pillars of National Grid's Clean Energy Vision, published in April 2022. Table 2-3 describes these pillars and the specific scenario assumptions informed by the pillars.

[62] See: NY CAC (December 2021). "Draft Scoping Plan Appendix G," sections 2.1 and 5.3. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scoping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.pdf**

Table 2-3. CEV.NY Scenario Assumptions Based on Clean Energy Vision Pillars

Pillars of National Grid's Clean Energy Vision[63]	CEV.NY Scenario Assumptions
1. Energy Efficiency in Buildings—continuation of programs to help customers accelerate energy efficiency improvements to buildings, ranging from deep retrofits to the support of more rigorous building codes for new buildings.	The CEV.NY scenario assumed that energy efficiency improvements will lead to a 30% reduction in building space heating and space cooling loads by 2050. This assumption is consistent with the Integration Analysis scenarios.
2. Fossil Free Gas Network—elimination of fossil fuels from existing gas network by 2050 through the substitution of renewable natural gas and green hydrogen.	The CEV.NY scenario assumed that gas deliveries will transition from fossil fuels to a mix of RNG and hydrogen, and that 20% of non-residential customers will transition to 100% hydrogen gas service by 2050. CEV.NY assumed that hydrogen blending in pipeline gas is assumed to reach 20% of total gas volume by 2050.
3. Hybrid Electric-Gas Heating Systems—continuation of support for customers by providing strategies and tools to capture and maximize the benefits of pairing electric heat pumps with existing gas appliances	The CEV.NY scenario assumed that by 2050, over 40% of residential and commercial buildings will transition to hybrid heating systems that combine an electric ASHP with a gas-fired heating system.
4. Targeted Electrification and Networked Geothermal—piloting new solutions like networked geothermal to help support cost effective targeted electrification of the gas network as well as providing support to customers using oil and propane with strategies to convert to heat pumps	The CEV.NY scenario assumed that by 2050, networked geothermal systems will serve 7% of customers, equal to roughly 630,000 households and 400 million square feet of non-residential building space statewide.

Source: Guidehouse analysis and National Grid (2022)[63]

2.4 Demand Forecast

To model the pathways for these three scenarios from 2020 to 2050, this study developed demand forecasts for energy consuming sectors (i.e., buildings, industry, and transportation) for each energy carrier, including electricity, natural gas, hydrogen, and other fuels.

2.4.1 Buildings Sector

Energy is consumed in the buildings sector to meet end-use demands such as space heating, space cooling, water heating, cooking, and other uses. The three scenarios modeled in this analysis had different assumptions regarding customer adoption of new space conditioning

[63] National Grid (April 2022). "Our clean energy vision: A fossil-free future for cleanly heating homes and businesses." Available at: **https://www.nationalgrid.com/document/146251/download**

systems and the electrification of different end uses over time. These assumptions led to different future energy demand profiles.

At the state level, this analysis projected the energy consumption for different end uses over time based on historical data of actual energy consumption in NY state, public forecasts of energy consumption through 2050, and data describing the shares of energy consumed for different end uses. Energy consumption forecasts by sector and by fuel type through 2050 were referenced from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) forecasts for the Mid-Atlantic region. For the residential and commercial sectors, the amount of energy consumption for different end uses (e.g., space heating, water heating) was estimated based on end-use consumption estimates in EIA's Residential Energy Consumption Survey (RECS) and EIA's Commercial Building Energy Consumption Survey (CBECS). Table 2-4 describes the data sources referenced in the development of the demand forecasts.

For each scenario, technology adoption curves were developed to estimate the amount of equipment conversions that occur in each year of the study period. Guidehouse used a model of customer energy demand to estimate the changes in energy consumption that would result from end-user equipment conversions of equipment used for space conditioning, water heating, and other end uses. Fuel-fired appliances and electric appliances have inherently different energy efficiency ratings, and the demand model accounted for changes in equipment energy efficiency associated with electrification. The demand model also accounted for equipment energy efficiency improvements over time due to replacement of older, less efficient appliances and improvements in appliance technology.

Table 2-4. Data Sources Referenced in Demand Forecast Model

Data Source	Relevant Data	Use in Buildings Sector Demand Model
EIA State Energy Data System (SEDS)	Energy consumption by sector, fuel type, and year for New York State	Historical energy use data was used to calibrate the energy demand forecast to actual data in years preceding the study period of 2020-2050.
EIA AEO	Forecast of energy consumption by fuel type through 2050	Energy consumption forecasts were used to estimate growth rates in energy consumption due to factors such as population growth and changes in economic activity.
EIA RECS	Share of residential energy consumption for different end uses in the Mid-Atlantic region	Used to disaggregate total residential energy consumption to estimate the amount of consumption for different end uses such as space heating and water heating.
EIA CBECS	Share of commercial energy consumption for different end uses in the Mid-Atlantic region	Used to disaggregate total commercial building energy consumption to estimate the amount of consumption for different end uses such as space heating and water heating.
NY CAC Draft Scoping Plan: Integration Analysis	Equipment energy efficiency parameters	Used in combination with energy consumption forecasts to estimate energy loads for different end uses. E.g., space heating loads were estimated based on projected space heating consumption and space heating equipment efficiency.
National Renewable Energy Laboratory (NREL) ResStock and ComStock analysis tools	Seasonal hourly load shapes of electricity and natural gas consumption for different building and heating equipment types	Load shapes were used to determine hourly energy consumption for representative seasonal and peak days.
U.S. Census American Communities Survey (ACS)	Housing unit counts, by housing type, geographic region (census tract scale), and primary heating fuel	Housing unit shares were used to determine the shares of buildings in different geographic regions (sub-state regions and operating company territories), to disaggregate statewide building counts at a more granular geographic scale.
NYSERDA Patterns & Trends: New York Energy Profiles	Energy consumption by county and fuel type	Energy consumption statistics were used to disaggregate statewide energy consumption at a more granular geographic scale.

Source: Guidehouse analysis

At the operating company level, National Grid's Gas Load Forecasting Team developed forecasts of customer counts and natural gas demand through 2050 using the same scenario assumptions applied in the statewide forecast. Guidehouse worked with National Grid's team to align adoption trends and energy efficiency assumptions between the statewide and operating company (OpCo)-level forecasts.

2.4.2 Industry and Transportation Sectors

As noted in Section 2.1, or specifically, the CEV.NY scenario adopted the same assumptions as the CAC's Strategic Use of Low-Carbon Fuels scenario for the industry and transportation sectors.[64]

2.5 Energy System Modeling

To model the energy systems needed to supply the forecasted demand, this study used an integrated energy system model, Guidehouse's LCP model. This model was adapted to the characteristics of New York's gas and electricity networks, including its energy supply-demand conditions, and its interties with neighboring regions. For each scenario, the LCP model selects a least cost pathway for the electricity and gas systems and identifies the investments that would be necessary to expand and maintain the systems to produce and deliver electricity, hydrogen, and methane. The pathways describe investments in generation and supply capacity, storage, and infrastructure, as well as when those investments will be needed. 0 provides detailed information about the LCP model.

2.5.1 Statewide and Regional Analysis

This study analyzed energy demand and supply at two levels of geographic granularity:

1. Modeling was conducted at the statewide level to ensure that scenarios comply with the Climate Act's GHG emissions requirements and to enable comparison with prior pathways studies, and

2. Modeling was conducted at the operating company (OpCo) level to assess the specific developments needed in National Grid's territories and the impacts on National Grid customers.

Data describing energy consumption is available at varying levels of geographic granularity. Historical data for consumption of all fuel types is available at the state level from EIA's SEDS. Historical data for sales of natural gas are available at the OpCo level from utility records and EIA-176 data. However, historical data for consumption of electricity and delivered fuels (e.g., propane and fuel oil) are not published for geographies specific to natural gas OpCos. To estimate the consumption of non-natural gas energy sources within the OpCo territories, this analysis used geographic information systems (GIS) analysis and U.S. Census data from the ACS.[65]

Guidehouse used several different data sources to disaggregate energy demand at the OpCo level from statewide demand projections for the buildings, industry, and transportation sectors. The buildings sector demand forecast was regionalized using the share of housing unit type by zone from the Integration Analysis for residential buildings and warehouse square footage as a

[64] The Integration Analysis' sector-level demand forecasts are published in the December 2021 Draft Scoping Plan Appendix G, Annex 2. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs.xlsx**

[65] U.S. Census table S2504 describes physical housing characteristics at the census tract level and includes counts of occupied housing units that use different heating fuels, including natural gas, propane, fuel oil, and electricity. Guidehouse used GIS systems to identify the census tracts located within National Grid OpCo territories and to calculate the number of housing units in OpCo territories that use different heating fuels. Census data is available at: **https://data.census.gov/table?q=s2504&tid=ACSST5Y2020.S2504**

proxy for commercial buildings. The industrial demand forecast was regionalized using the fuel demand by subsector and zone provided in the Integration Analysis technical appendices. The transportation sector demand was apportioned to the model regions using county-level vehicle miles travelled (VMT) from the NY Department of Transportation.

Table 2-5. New York Regional Allocation Method from State to LCP Model Region Level

Sector	Regional Allocation Method	Source
Buildings (Residential)	Share of housing unit type by CLCPA zone	Integration Analysis
Buildings (Commercial)	Commercial square footage by CLCPA zone	Integration Analysis
Industry	Industrial fuel demand by subsector and by CLCPA zone	Integration Analysis
Transportation	VMT by county	Integration Analysis

Source: Guidehouse analysis

2.5.2 Modeling Assumptions

This analysis leveraged the sources and assumptions cited in the CAC Integration Analysis for most baseline modeling assumptions, including overarching economic drivers such as population growth, building stock turnover, and technoeconomic characteristics.

This study incorporated assumptions specific to National Grid in cases where the Integration Analysis did not provide data, where Integration Analysis data was out-of-date, or where utility-specific data is more relevant than the CAC's statewide assumptions. For instance, National Grid's Gas Load Forecasting Team provided forecasts of annual gas consumption and design day demand at the OpCo level, with input from the Guidehouse pathways assumptions.

In cases where neither National Grid nor the Integration Analysis provided applicable inputs or assumptions for a topic, Guidehouse used internal expert research and judgement to develop assumptions.

2.5.2.1 Assumptions Appendix

The inputs and assumptions used for this study are documented in a spreadsheet file that accompanies this report.[66] The spreadsheet file is organized by topic into individual worksheets that contain assumptions and citations to data sources. National Grid provided versions of the inputs and assumptions spreadsheet for stakeholder review on August 10 and November 14, 2022. Stakeholders provided feedback and comments on these earlier versions, and National Grid incorporated stakeholder feedback during the development of the analysis.

2.5.2.2 Leak-Prone Pipe and Targeted Electrification

National Grid operates about 35,000 miles of gas pipeline through New York and New England and is required by the U.S. Department of Transportation's Pipeline and Hazardous Materials

[66] TO INCLUDE FILE NAME AND LINK TO DOCKET.

Safety Administration (PHMSA) to report information such as total mileage of pipelines and pipeline material types per 49 CFR Parts 191, 195. As of 2021, about 22% of National Grid's distribution pipelines in New York State are made of materials considered to be leak-prone, including unprotected steel and cast/wrought iron.

Table 2-6. National Grid Leak-Prone Pipe in New York State (2021)

Operator	Pipeline Miles		
	LPP	Non-LPP	Total
Brooklyn Union Gas Company (KEDNY)	1,437	2,753	4,189
KeySpan Gas East Corporation (KEDLI)	2,782	5,617	8,399
Niagara Mohawk Power Corp (NMPC)	404	8,498	8,901

Source: U.S. Dept. of Transportation, Pipeline and Hazardous Materials Safety Administration.[67]

National Grid has annual and multi-year LPP replacement targets that are established through rate cases. Based on current schedules, LPP segments will be fully replaced by 2032 for Niagara Mohawk, and 2045 for KEDNY and KEDLI. Guidehouse, in collaboration with National Grid, assumed that, as gas infrastructure is retired across all scenarios due to targeted electrification, current investments in LPP replacement will decrease linearly with the total mileage of gas pipeline (i.e., if 10% of gas pipeline is retired by 2050, then LPP replacement activity will decrease by 10% by 2050). Based on guidance from National Grid, this study assumed that the earliest year in which reduction of LPP replacement activities could begin is 2025 for NMPC, 2028 for KEDLI, and 2034 for KEDNY.

A number of considerations inform these assumed timelines, including settled replacement targets, pipeline safety regulations, operational considerations, and customer and network density, all of which increase the challenge of targeted electrification. With respect to KEDNY, the majority of LPP is cast iron pipe which has an inherently higher leak rate and associated risk, requiring continuation of efforts to prioritize replacement of these pipes into the 2030s.

The final Scoping Plan recognizes the emissions and safety impacts of LPP replacement, noting that "much of the leak-prone pipe replacement is necessary for safety reasons and will continue to produce real reductions in emissions, while additional replacements may be necessary for further emission reductions."[68] The Scoping Plan recommends continued prioritization of LPP replacement, and notes that the costs of repair may not be justified on segments where decommissioning may be possible.[69]

Figure 2-2 illustrates the projected lengths of LPP replacement by decade for National Grid's current LPP plans (assuming no gas network decommissioning), under a scenario where 10% of the gas network is decommissioned by 2050 (as in the CEV.NY scenario), and under a scenario where 90% of the gas network is decommissioned by 2050 (as in the Integration Analysis scenarios). The chart illustrates that decommissioning will have little impact on LPP

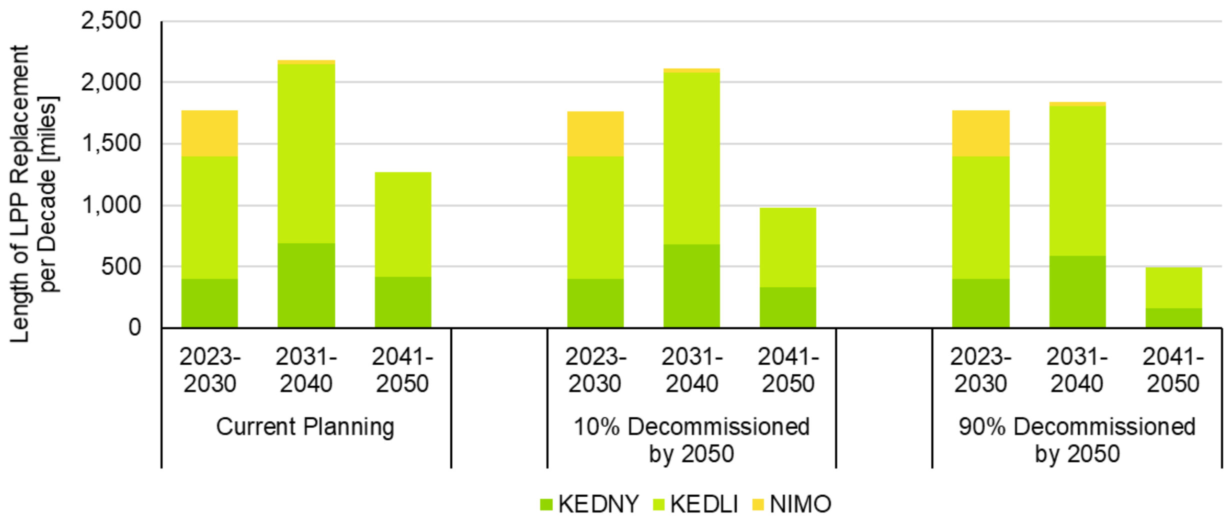
[67] US DOT, PHMSA. "Annual Gas Distribution 2021.xlsx" Available at: **https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids**

[68] New York's Scoping Plan, page 353. Available at: **https://climate.ny.gov/-/media/project/climate/files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf**

[69] New York's Scoping Plan, page 358. Available at: **https://climate.ny.gov/-/media/project/climate/files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf**

replacement activity before 2030, but that gas network decommissioning could result in reduced LPP replacements in later decades.

Figure 2-2. Leak-Prone Pipe Replacement Forecast for Different Decommissioning Outlooks, by Decade



Source: Guidehouse analysis

A key assumption behind the reduction in LPP replacement is that customers will disconnect from the gas network in a coordinated manner, through targeted electrification. Figure 2-3 provides diagrams to illustrate the difference between non-targeted electrification and targeted electrification. Figure 2-3(a) illustrates a typical gas network, with a main pipeline supplying branches that provide service to individual customers. Figure 2-3(b) illustrates a potential future network where customers disconnect from the grid in an uncoordinated fashion. In this version without targeted electrification, LPP replacements could not be curtailed, because the pipeline main and branches need to be maintained to provide service to remaining customers. Figure 2-3(c) illustrates a targeted electrification approach, where all customers on a branch are electrified, so individual branches can be removed from service. In this version of the future, reductions in LPP investments are possible, because some branches of the network no longer need to be maintained.

Figure 2-3. Illustration of Electrification Approaches

(a) Current Natural Gas Network | (b) Future Gas Network, Without Targeted Electrification | (c) Future Gas Network, With Targeted Electrification

Source: Guidehouse analysis

As illustrated above, a targeted electrification approach may enable a reduction in LPP replacements and network operations and maintenance (O&M) costs. However, the feasibility of this approach and the potential for gas system cost avoidance is uncertain. Among other things, feasibility is influenced by the upfront equipment cost of whole-building electrification, customer willingness to opt-in to electrification programs and technologies, uncertainty about the timelines necessary to fully electrify customers on individual segments, and the utilities' ability recoup the costs of stranded assets.

2.5.2.3 Renewable Natural Gas

Renewable natural gas (RNG) is captured biogas (the gaseous product of the decomposition of organic matter) that has been processed to pipeline standards. RNG can be sourced from existing waste streams and biomass, and it can be used as a "drop-in" fuel that is able to be transported through existing gas networks. For all scenarios, this analysis assumed that consumption of conventional geologic natural gas is eliminated by 2050, and that any remaining gas demand in 2050 and beyond is served by RNG, hydrogen, or a blend of RNG and hydrogen.

This analysis assumed that RNG may either be sourced from production facilities developed within New York or be imported from outside the state. The costs associated with RNG were modeled differently for in-state and out-of-state sources. For in-state RNG sources, the cost analysis accounted for (1) the capital cost of new RNG production facilities and the infrastructure needed to connect these facilities to existing gas grid, and (2) the ongoing O&M costs necessary to operate RNG production facilities. These costs were sourced from NYSERDA's 2022 assessment or RNG potential study, which found that New York State has the potential to produce between 46-150 TBtu/year of RNG by 2040.[70] For out-of-state RNG sources, the cost analysis used an assumed purchase price for RNG on a $/MMBtu basis. This cost included costs associated with producing RNG and transporting it from the source of

[70] NYSERDA (2022). "Potential of Renewable Natural Gas in New York State." Available at: **https://www.nyserda.ny.gov/-/media/Project/Nyserda/files/EDPPP/Energy-Prices/Energy-Statistics/RNGPotentialStudyforCAC10421.pdf**

production to New York and included the cost of environmental attributes of the fuel. The procurement of RNG attributes is consistent with National Grid's fossil free vision.

The potential for in-state and out-of-state RNG production is constrained in the analysis based on estimated availability of certain waste and biomass feedstocks. This study considered the potential for RNG production from the feedstocks listed in Table 2-7. This study excludes potential RNG production from energy crops and municipal solid waste feedstocks due to concerns about the sustainability and emissions implications of these resources.

Table 2-7. RNG Production Technologies and Feedstocks in Scope for This Study

RNG Production Technology	RNG Feedstocks
Anaerobic Digestion	Animal manure, food waste, landfill gas, water resource recovery facilities
Thermal Gasification	Agricultural residue, forestry and forest product residue

Source: Guidehouse

The analysis assumed that RNG volumes sourced from in-state production could not exceed the potential production calculated for the "Optimistic Growth" scenario defined in NYSERDA's RNG potential study. Under that scenario, New York-sourced RNG could reach 81.4 TBtu of production in 2040.[71] Using growth trends published in American Gas Association (AGA) (2022),[72] Guidehouse extrapolated the potential production in 2040 to estimate that New York State's RNG potential could reach 45.1 TBtu in 2030 and 135.0 TBtu in 2050. To estimate the amount of potential RNG imports available from out-of-state, this analysis referenced studies from the American Gas Foundation[73] (AGF) and AGA (2022) . The AGF study estimated the potential RNG production in 2040 from different feedstocks for each U.S. state. This analysis assumed that National Grid may import RNG from states in the Eastern U.S., but, in order to recognize that there will be competing demands for this resource, assumed that the share of RNG potential available to National Grid would be limited to the utility's current share of residential and commercial gas sales in the Eastern U.S.[74] The AGA report provided estimates of RNG potential production in 2030, 2040, and 2050, and this analysis used the AGA figures to estimate RNG potentials for New York and Eastern U.S. states in 2030 and 2050.

The New York Department of Environmental Conservation (DEC) provides a draft framework for GHG emissions accounting consistent with the CLCPA's targets for gross emissions reductions.[75] This analysis calculated the emissions associated with RNG consumption in a manner consistent with the DEC's draft accounting framework, which counts the biogenic

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[71] *Ibid.* Note that this figure excludes RNG potential from energy crops and municipal solid waste.

[72] AGA (2022). "Net-Zero Emissions Opportunities for Gas Utilities." Available at: **https://www.aga.org/events-community/events/net-zero-emissions-opportunities-for-gas-utilities--financial-community/**

[73] AGF (2019). "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment." Available at: **https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf**

[74] The estimation of available RNG imports is based on residential and commercial sector gas sales because this study assumes that natural gas consumption will be largely eliminated from the industry and power sectors. Data from the EIA indicates that KEDNY, KEDLI, and NMPC gas sales comprise 7.2% of Eastern US gas sales for Residential, Commercial, Non-Firm Demand Response, and other non-industrial non-power demand.

[75] NYSERDA and NY DEC (2021). "Technical Documentation: Estimating Energy Sector Greenhouse Gas Emissions Under New York State's Climate Leadership and Community Protection Act." Available at: **https://www.dec.ny.gov/docs/administration_pdf/energyghgerg.pdf**

emissions associated with combustion of RNG in New York toward gross emissions limits specified in the CLCPA.

2.5.2.4 Hydrogen

Hydrogen fuel played a role in all three scenarios by serving end uses that are hard to electrify (such as heavy transportation and high temperature industrial processes) and by providing a zero-carbon firm electric generation resource (hydrogen gas turbines) capable of long-term storage. For hydrogen storage, the analysis assumed that hydrogen may be stored for long durations in salt caverns in northwest New York.[76]

All of the hydrogen modeled in this analysis meets the definition of "green hydrogen." That is, it is produced by electrolyzers powered by electricity from renewable sources. This analysis assumed that hydrogen may be sourced from production facilities developed within New York and that hydrogen may also be imported from outside the state. The costs associated with hydrogen were modeled differently for in-state and out-of-state sources. The in-state hydrogen production costs were aligned with assumptions in the CAC's Integration Analysis, which account for (1) the capital cost of new electrolyzer equipment and the infrastructure necessary to connect electrolyzers to hydrogen demand centers, and (2) the ongoing O&M costs needed to operate electrolyzers including the cost of the electricity to power them.[77] For hydrogen imported from out-of-state, the cost analysis used an assumed purchase price for hydrogen on a $/MMBtu basis, referenced from the Massachusetts Department of Public Utilities (DPU) 20-80 proceeding.[78] The modeling results in Section 3.5 show that in all scenarios, hydrogen demand will be met by in-state hydrogen production.

The CEV.NY scenario assumed that natural gas distribution companies will begin blending hydrogen in natural gas deliveries as early as 2030, but that the initial rates of hydrogen blending will be low (1% by energy) and will increase gradually over time, up to a maximum blending ratio of 7% hydrogen by energy in 2050.

2.5.2.5 Networked Geothermal

Networked geothermal uses centralized ground-source heat pumps to provide heating and cooling service to customers via district pipe networks. Compared to standalone ASHP systems, networked geothermal systems have better winter performance and place lower strain on the electric grid. This is because networked geothermal systems exchange heat with the ground (which stays at a constant temperature below a certain depth) instead of with the outside air, which fluctuates more widely. For this reason, ground-source heat pumps have higher efficiency and lower electric needs. Figure 2-4 illustrates how a networked geothermal system would meet heating and cooling needs of buildings.

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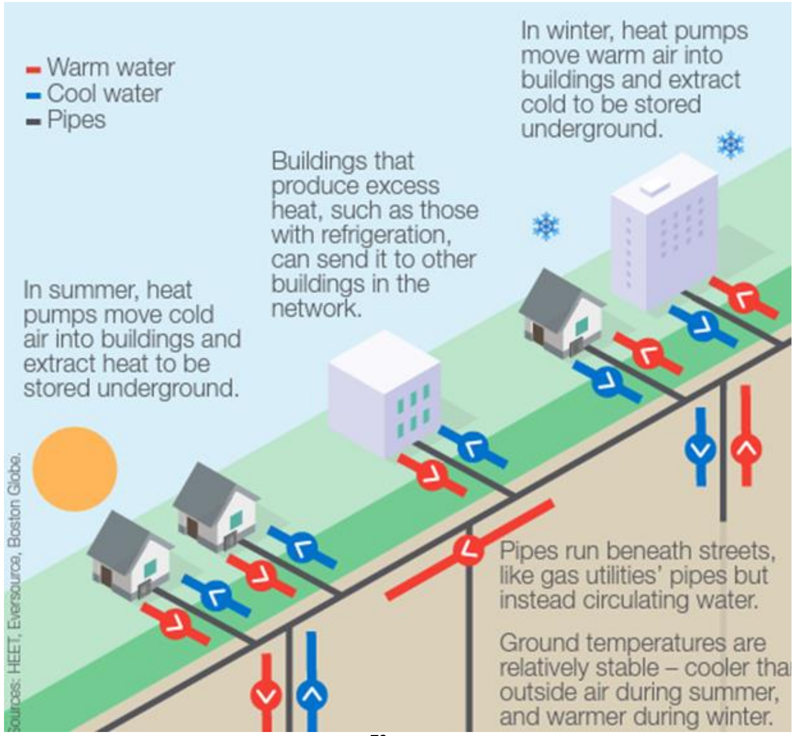
[76] This assumption is based on findings presented in Sandia National Laboratories (2009). "Overview of Geologic Storage of Natural Gas with an Emphasis on Assessing the Feasibility of Storing Hydrogen." Figure 3. Available at: **https://www.osti.gov/biblio/975258**

[77] The Integration Analysis hydrogen cost assumptions are published in the "Hydrogen Costs" tab of the December 2021 Draft Scoping Plan Appendix G, Annex 1. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-1-Input-Assumptions.xlsx**

[78] MA DPU 20-80 Independent Consultant Report, Appendix 4, "Renewable Fuels Supply Curve" tab. Available at: **https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633268**

Figure 2-4. Schematic of a Networked Geothermal Street



Source: National Grid (April 2022).[79]

Network geothermal systems are in the early stage of development, and cost estimates for full-scale deployment of the technology are preliminary. Based on guidance from National Grid's Future of Heat team, this analysis estimated that the energy efficiency and installation cost of networked geothermal systems will be similar to those of standalone geothermal heat pumps. The CEV.NY scenario assumed that networked geothermal systems will be piloted for several years before the number of installations begins to increase in the early 2030s. The number of customers connected to networked geothermal installations is projected to grow slowly and then ramp up in the 2040s until networked geothermal serves about 7% of all statewide heating load in 2050. Due to the challenges associated with installing pipeline networks in dense urban areas, this analysis assumed that networked geothermal systems will be about twice as prevalent in Upstate New York as in Downstate New York.

2.6 Cost Modeling

As referenced in the prior section, the LCP model identified the least cost pathway for each scenario from a total cost perspective. That is, the model chose investments that minimize the total upfront and ongoing costs paid over the analysis period, regardless of what entity or group would pay in practice. This section describes the process of allocating the cost of each scenario to those entities, and how costs are subsequently passed on to ratepaying customers.

[79] National Grid (April 2022). "Our clean energy vision: A fossil-free future for cleanly heating homes and businesses." Available at: **https://www.nationalgrid.com/document/146251/download**

2.6.1 Upstream (Wholesale Supply) Energy Network Costs

The New York energy system is deregulated. For the purposes of this study, the wholesale power generation markets were considered an “entity” at which wholesale energy prices are set.

The generation supply resource upfront and ongoing costs were estimated as the quantity of added supply generation capacity and the volumes of supply generated multiplied by the upfront, fixed O&M, and variable O&M unit costs. The unit cost assumptions are listed in the latest filed assumptions appendix.[80] Fuel import costs were similarly estimated for both for electric power plant inputs like coal plants and for in scope delivered fuels like natural gas imported into the state.[81] Once assembled, this data represented the total of wholesale supply expenses, which are presented for comparison at a statewide level for each scenario.

In practice, the upfront cost of added generation supply is recouped over time at some rate of return through wholesale energy prices. To estimate this wholesale energy price then, the upfront costs of added generation supply were first levelized using a fixed charge rate. The fixed charge rate assumptions are listed in the latest filed assumptions appendix. This was then added to the existing baseline of levelized investment costs that are currently setting wholesale supply prices. Note that this was only relevant to the electric power generation sector because it was assumed as of 2020 there was negligible electrolyzer or RNG-generation on the wholesale market. This baseline-levelized investment cost was estimated as the 2020 EIA NYS wholesale electric revenues minus fuel import and variable O&M costs. Once the total levelized upfront cost was estimated, the ongoing O&M costs and fuel import costs were added to establish a total annualized cost. Note that fuel import costs at this stage also included the cost of other modeled fuels at the soon-to-be-estimated wholesale price, such as natural gas-powered electric power plants.[82] That cost was then divided by annual generated supply to yield a wholesale price.[83]

This wholesale price represented a first-level estimate of the price set within each region of the state. A secondary impact was the price of wholesale energy transfers between regions. The final estimated wholesale price was then a weighted average of the price of energy supplied within a region and the price of intrastate imports grossed up for assumed line losses.

Note that this estimate of wholesale prices represented an annual average based on expected returns by generator type. In practice, the NYISO locational-based marginal pricing (LBMP) market for electricity and the wholesale market for delivered fuels are complex and will likely experience periods of volatility. These markets also vary throughout the year, such that prices during peak demand times are likely higher than annual averages. Therefore, the prices

[80] Available as “Guidehouse CLCPA Assumptions Appendix 2.0.xlsx”, filed to Case 19-G-0309 on November 21, 2022, available at: **https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D52B8106-D18D-4BC3-8586-7A0880A44DB3}**

[81] “In scope delivered fuels” include natural gas, renewable natural gas, and hydrogen, and exclude fuel oil, propane, wood, etc.

[82] The only instance of potential cyclic dependency in price setting with this method is with hydrogen-powered electric generation plants being used to set the price of electricity, where hydrogen prices could also be impacted by the price of electricity to electrolyzers. This is avoided by assuming that electrolyzers are co-located with renewable resources with an LCOE of 3.4¢/kWh.

[83] Where “generated supply” includes both supply generated by in-state power generation facilities and supply imported from out of state.

presented in this study should not be utilized as forecasts of actual wholesale energy prices, but rather as a metric for comparing the cost of scenarios normalized by throughput.

2.6.2 Downstream (Retail Delivery) Energy Network Costs

The cost of delivering energy to end users through transmission and distribution infrastructure is incurred by utilities. Analogous to wholesale supply generation capacity costs, the upfront and ongoing costs of added transmission and distribution (T&D) infrastructure were captured for each scenario.[84] These were added to baseline utility capital and operating expenses to estimate the total cost of delivery for each scenario. Note that current baseline costs were based on utility filings, and they were forecasted forward in time based on assumed elasticities to customer count and throughput.[85] When combined with supply side costs, this total cost represents the total energy system expense paid within the state. This is presented for each scenario for comparison.

As with wholesale costs, upfront expenses were levelized by utilities to pass on to customers. Rather than using a simplified fixed charge rate to annualize these costs however, a more rigorous calculation was completed as part of the revenue requirement. The annual revenue requirement is the sum of this levelized cost and ongoing O&M expenses. It is explained further in the following subsection. This revenue requirement can be divided by customer count or delivered supply to yield normalized cost metrics that could be interpreted as indicative cost per customer and delivered prices absent changes to depreciation approaches or other reforms.

Note that this normalization of revenue requirements for National Grid customers simplified much of the customer bill impact analysis normally performed as part of rate cases. These metrics distributed costs across all customer classes to present the cost to an “aggregate” customer. It’s important to consider, then, that not only would stratification be expected between residential and commercial customers, for example, but even customers within the same rate class will have varying energy costs given variations in energy use profiles.

2.6.2.1 Revenue Requirement

Estimating the revenue requirement impact of utility investment aims to replicate how delivery rates are set in rate cases. The revenue requirement consists of annual fuel purchases and O&M costs, including depreciation expenses, plus an annual taxable return on rate base. The rate base is the net plant-in-service (i.e., cumulative upfront investments minus cumulative depreciation) minus any deferred income tax from accelerated depreciation of assets.

The main calculation then was to annualize investments by calculating their impact on net plant-in-service and deferred income tax. To do this, each asset category had an assigned straight-line book depreciation rate and a tax depreciation rate. Then capital expenses in each year were added to cumulative gross plant-in-service, and depreciation of the assets at the assigned book depreciation rate begins.[86] This depreciation, along with depreciation of existing assets at the current filed rate, accumulates over time, and was subtracted from gross plant-in-service to yield net plant-in-service. Separately, the tax depreciation over time was calculated for assets added in each install year based on a defined tax depreciation schedule. This tax depreciation

[84] The associated unit cost assumptions are listed in the latest filed assumptions appendix.

[85] The elasticity assumptions are listed in the latest filed assumptions appendix.

[86] Note this assumes an immediate closing of assets. In practice, it may take a few years after construction is completed for an asset to be included as plant in-service and for depreciation to begin.

was similarly accumulated from the 2020 accumulated tax depreciation reserve. The difference between accumulated book depreciation and accumulated tax depreciation in every year, multiplied by the aggregate tax rate, represented the accumulated deferred income tax. The net plant-in-service minus the deferred income tax in every year represented the rate base, which was then multiplied by an assumed rate of return (the pre-tax Weighted Average Cost of Capital by utility) to yield the pre-tax return on rate base.[87]

Note that this approach to calculating utility revenue requirement assumed the existing regulatory structure persists through 2050. That included maintaining current approved book depreciation rates, tax depreciation rates, pre-tax weighted average cost of capital (WACC), and the average combined effective tax rate.

2.6.3 Customer Costs

Two main categories of cost to end-user customers that were quantified in this study: (1) end-user investment in energy efficiency upgrades and heating equipment, and (2) the cost of energy bills. The end-user efficiency and equipment costs applied assumed unit costs to the level of efficiency and heating equipment upgrades identified in each scenario.[88] The energy bill was estimated using assumed usages per customer, multiplied by the supply and delivery price metric estimates identified previously. Given the caveats to the energy prices, the estimates of energy bills are intended to be indicative and allow for comparison across scenarios. Note that this cost analysis excludes any state or federal incentives to reflect total cost to the state.

2.6.4 Waste & Agriculture Costs

While the primary focus of this study was on the energy network (i.e., energy for residential and commercial buildings, industry, and transportation sectors) and, therefore, energy system costs, this study also quantified the relative costs of agriculture and waste emissions savings. This study replicated the approach to quantifying the costs that the CAC Integration Analysis used.

[87] This return is then taxed, but that tax is not additive to the revenue requirement.

[88] The associated unit cost assumptions are listed in the latest filed assumptions appendix.

3. Analytical Results

This section presents modeling outputs for the three scenarios and includes projections of customer counts, energy consumption, GHG emissions, natural gas and electricity capacity and supply, energy system costs, and customer costs.

3.1 GHG Emissions Reductions

In each of the three modeled scenarios, GHG emissions are projected to decline to meet the Climate Act's GHG 2030 and 2050 emissions targets, as shown in Figure 3-1. The figure illustrates that the pathways to CLCPA emissions targets appear similar across the scenarios. This analysis calculated GHG emissions in a manner consistent with the New York DEC's draft accounting framework.[89]

In the energy consuming sectors of the economy (buildings, industry, and transportation), GHG emissions reductions are driven by energy efficiency, electrification, and the substitution of RNG and hydrogen for fossil fuels. For buildings, electrification of heating devices, such as air-source heat pumps, building shell upgrades, and usage of RNG in lieu of natural gas are the main factors behind emissions reductions between 2020 and 2050. In the industry sector, electrification, energy efficiency improvements, and the substitution of hydrogen for fossil fuels drives the projected decrease in GHG emissions.

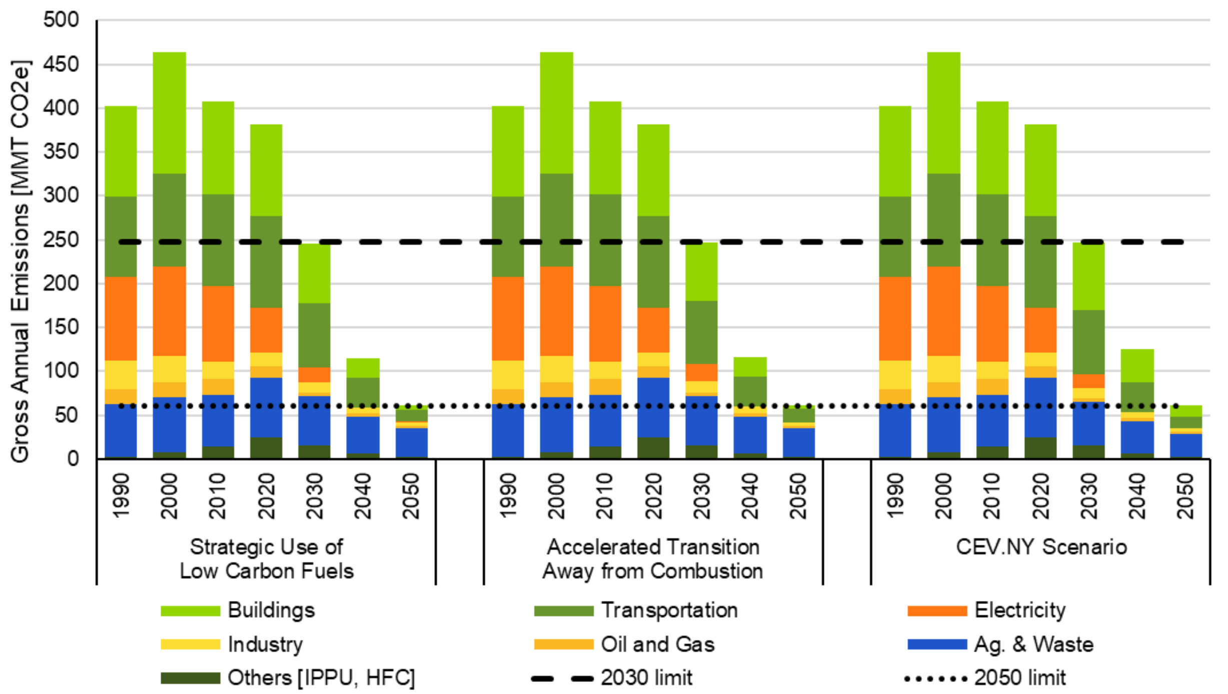
From 2020 to 2050, gross GHG emissions from the buildings sector are projected to decrease by 94.8% in the Strategic Use scenario, by 95.7% in the Accelerated Transition scenario, and by 88.3% in the CEV.NY scenario.

Compared to the Integration Analysis scenarios, the CEV.NY scenario assumed the buildings sector will produce more emissions in 2050 under a gross emissions accounting approach due to lower rates of whole-building electrification and greater consumption of RNG for space heating and other end uses.

For non-energy related emissions (e.g., from the oil & gas, agriculture, waste, and other sectors) this analysis adopts the GHG emissions projections published in the CAC's Integration Analysis.

[89] The DEC provides a draft framework for GHG emissions accounting consistent with the CLCPA's targets for gross emissions reductions. NYSERDA and NY DEC (2021). "Technical Documentation: Estimating Energy Sector Greenhouse Gas Emissions Under New York State's Climate Leadership and Community Protection Act." Available at: **https://www.dec.ny.gov/docs/administration_pdf/energyghgerg.pdf**

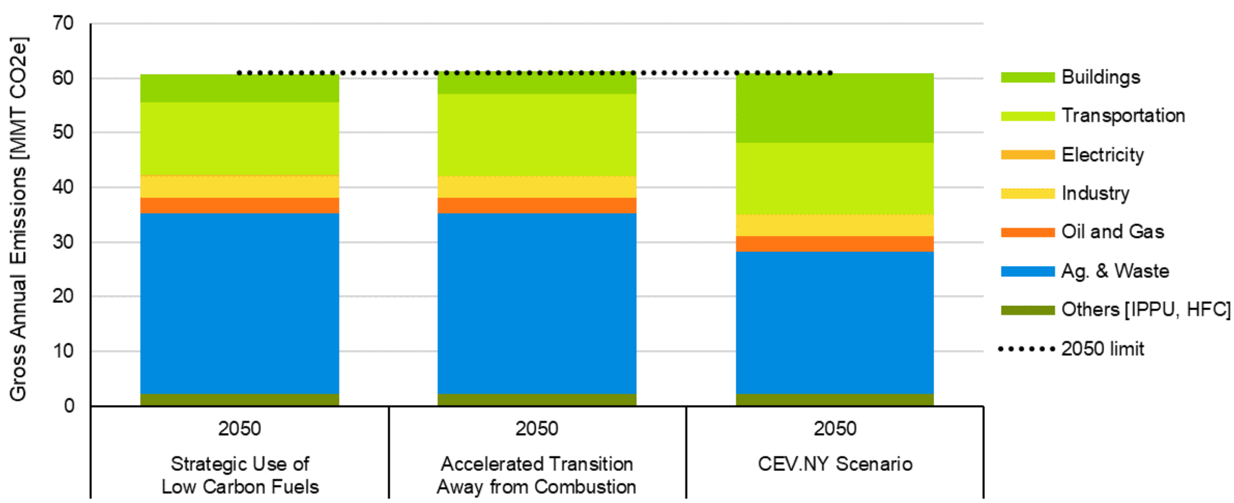
Figure 3-1. Gross GHG Emissions by Scenario and Source, 2020-2050



Note: Years 1990-2010 are historical data reported in DEC New York State Emissions Inventory.[90] Years 2020-2050 are modeled emissions based on scenario demand forecasts.

Source: Guidehouse analysis

Figure 3-2. Gross GHG Emissions by Scenario and Source, 2050 Detail



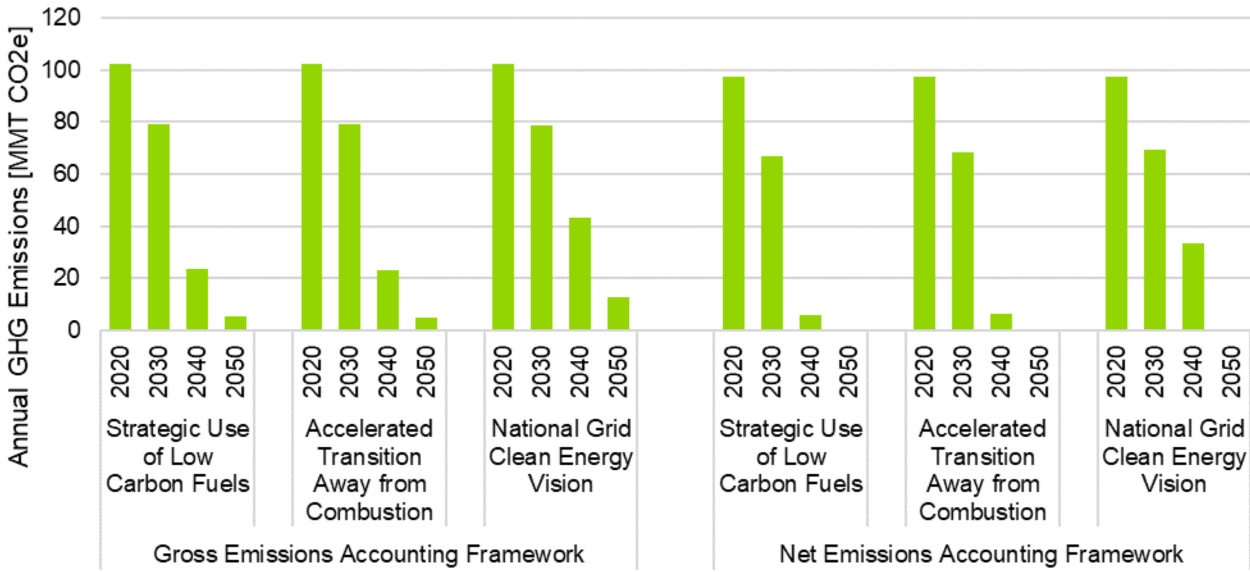
Source: Guidehouse analysis

Figure 3-1 and Figure 3-2 above present GHG emissions calculated using a gross emissions accounting framework. Figure 3-3 below compares GHG emissions from the buildings sector, calculated under a gross emissions framework and a net emissions framework. This

[90] New York DEC (2021). "2021 Statewide GHG Emissions Report" Available at: **https://www.dec.ny.gov/energy/99223.html**

comparison illustrates that under a net emissions accounting framework, which is inclusive of avoided methane emissions and counts RNG as GHG-neutral, the buildings sector achieves net zero emissions in 2050 for all scenarios.

Figure 3-3. Buildings Sector GHG Emissions, Gross and Net GHG Accounting Frameworks (2020-2050)



Source: Guidehouse analysis

3.2 Building Heating System Adoption

The three scenarios have different assumptions about how energy usage in New York will shift over time. The type of heating system has a large impact on customer energy demand, and Figure 3-4 illustrates the differences in these assumptions by scenarios for residential and commercial customers.

For the Integration Analysis scenarios, the trajectories in Figure 3-4 are referenced from the CAC Draft Scoping Plan.[91] The main difference between the heating system assumptions for the two Integration Analysis scenarios is that the Strategic Use scenario assumed that a portion of customers adopt hybrid heating systems (dark green area on Figure 3-4) between 2030 and 2050. There are three main differences between the CEV.NY scenario and the Integration Analysis scenarios:

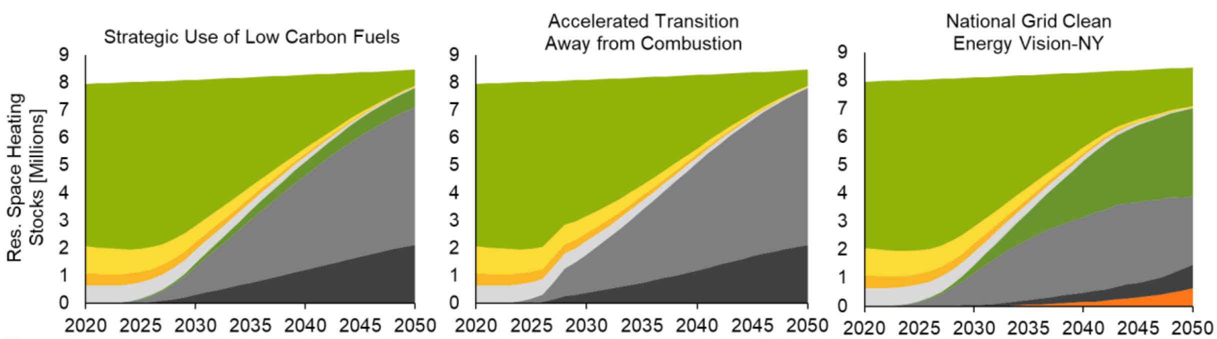
- The CEV.NY scenario had a much larger role for hybrid heating systems (also referred to as partial heat pumps), with hybrid heating systems making up about 35% of heating system stocks in 2050.

[91] The Integration Analysis' heating system stock forecasts are published in the December 2021 Draft Scoping Plan Appendix G, Annex 2. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs.xlsx**

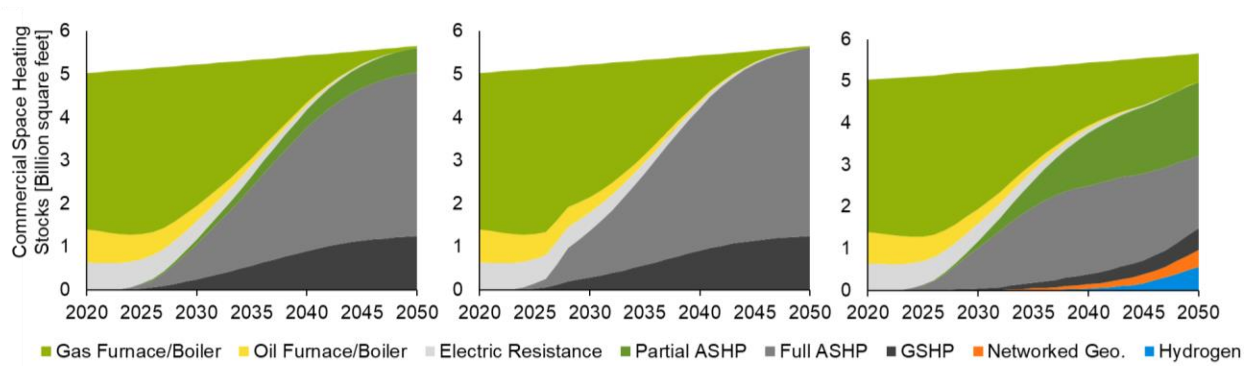
- The CEV.NY scenario assumed a larger portion of customers will retain high efficiency gas-fired systems.
- Compared to the Integration Analysis scenarios, the CEV.NY scenario assumed a more gradual adoption of geothermal heating systems and assumed that the share of customers who adopt geothermal heating systems will be split between standalone ground-source heat pumps (labeled as GSHP) and networked geothermal systems.

Figure 3-4. Statewide Residential and Commercial Heating System Stocks, 2020-2050

(c) Residential Space Heating Stocks



(d) Commercial Space Heating Stocks



Source: Guidehouse analysis

3.3 Customer Count Forecasts

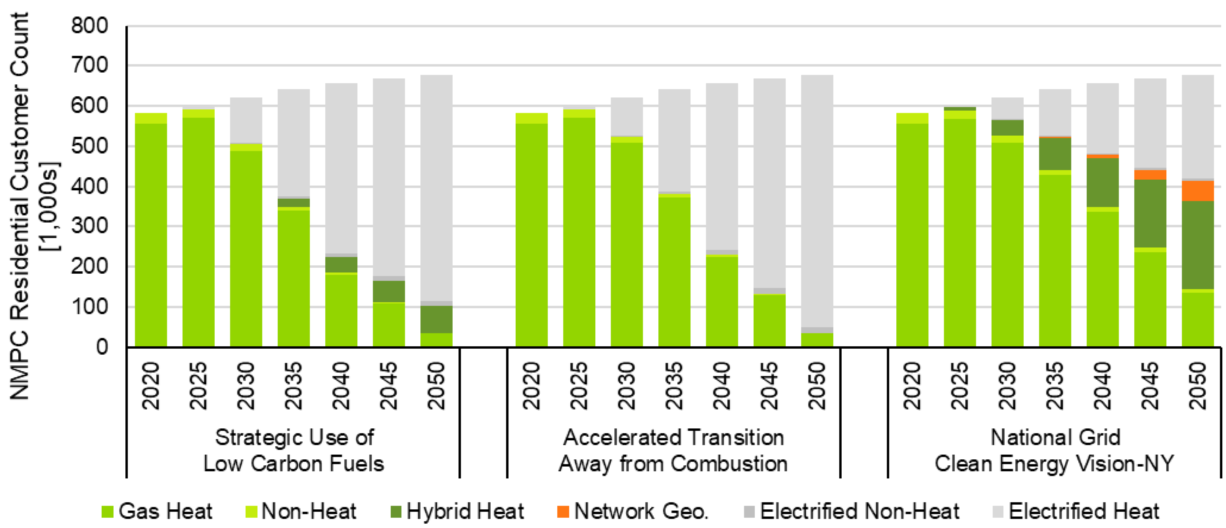
The following figures present projected counts of residential and non-residential customers on National Grid's gas distribution networks in Upstate and Downstate New York. In these stacked column charts, the total heights of the columns show National Grid's unadjusted baseline forecasts of retail customers. In other words, the column heights show the projected number of customer meters that National Grid would serve in the absence of New York's Climate Act. National Grid's unadjusted baseline forecasts include increases in meter counts due to population growth and the addition of new customers converting from delivered fuel (e.g., fuel oil) heating systems.

The gray portions of each column indicate customers projected to leave the gas network due to electrification. The colored portions of the columns show the remaining National Grid customers, which are subdivided to show: customers that use gas for heating (dark green), customers that have gas service only for non-heating purposes (light green), customers that transition to hybrid heating systems (yellow), customers that transition to full hydrogen service (orange), and customers that transition to networked geothermal (reddish orange)

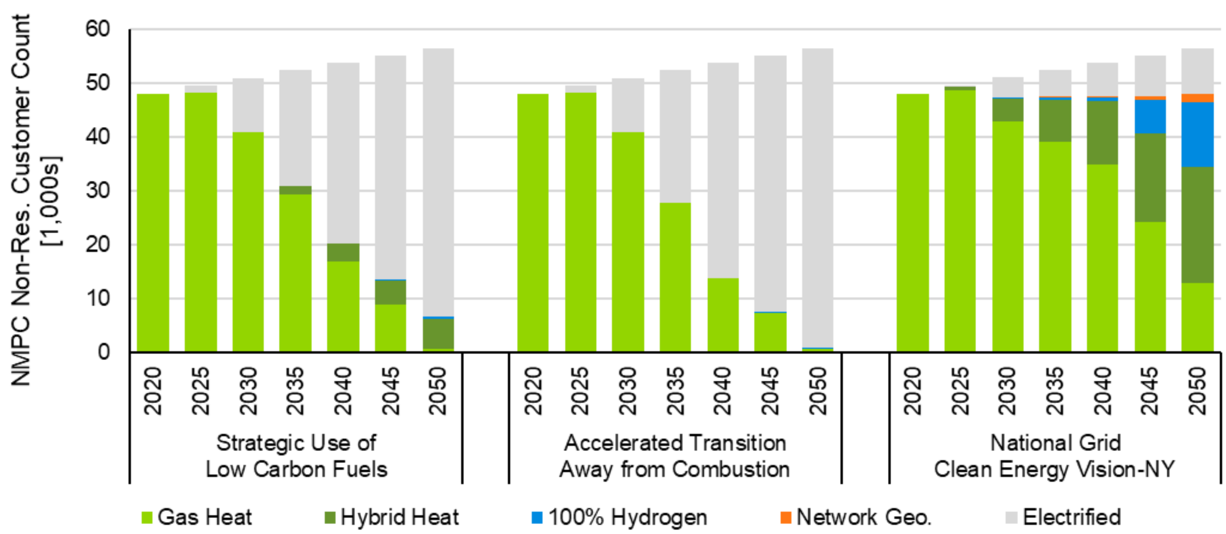
These charts show that in the Integration Analysis scenarios, National Grid customer counts decline quickly and few gas customers would remain on National Grid's networks in 2050. In contrast, the CEV.NY scenario projects a slower rate of decline in customer counts, since many customers would keep their gas connections when they transition to a hybrid heating system. In the non-residential sector, the CEV New York scenario shows that thermal customer counts (including customers receiving blended pipeline gas, 100% hydrogen, and networked geothermal service) would remain almost flat through 2050, but that the mix of customers would evolve over time.

Figure 3-5. Niagara Mohawk Customer Count Forecasts, 2020-2050

(a) NMPC Residential Customer Counts (thousands)



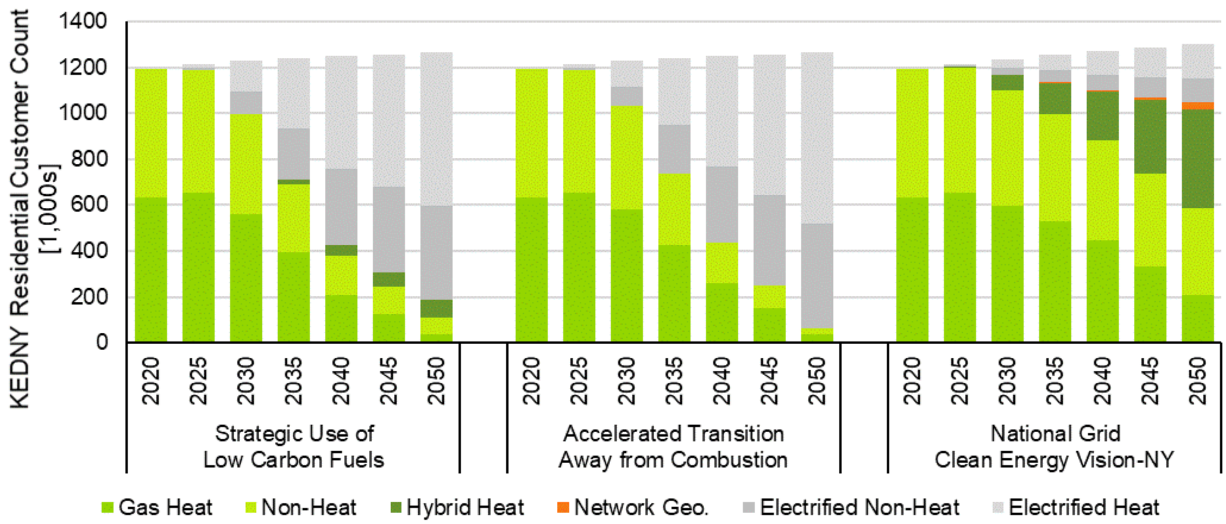
(b) NMPC Non-Residential Customer Counts (thousands)



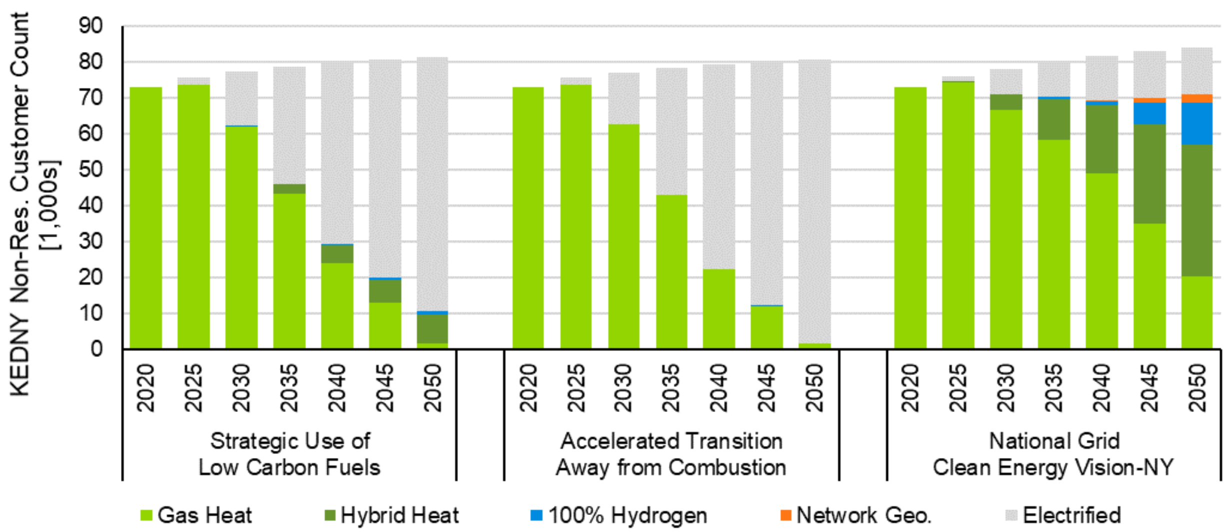
Source: Guidehouse analysis

Figure 3-6. KEDNY Customer Count Forecasts, 2020-2050

(a) KEDNY Residential Customer Counts (thousands)



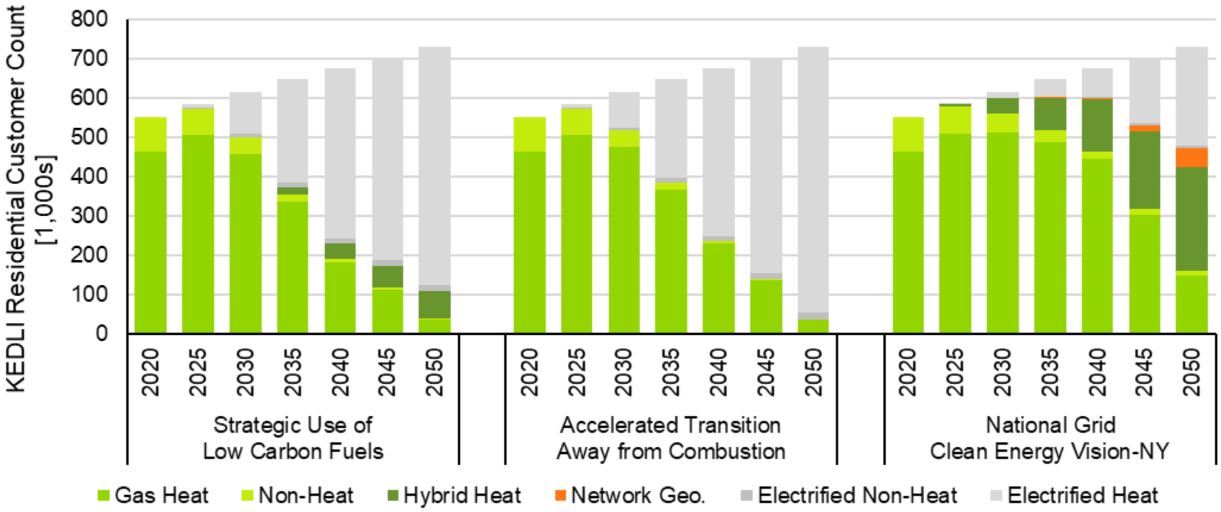
(b) KEDNY Non-Residential Customer Counts (thousands)



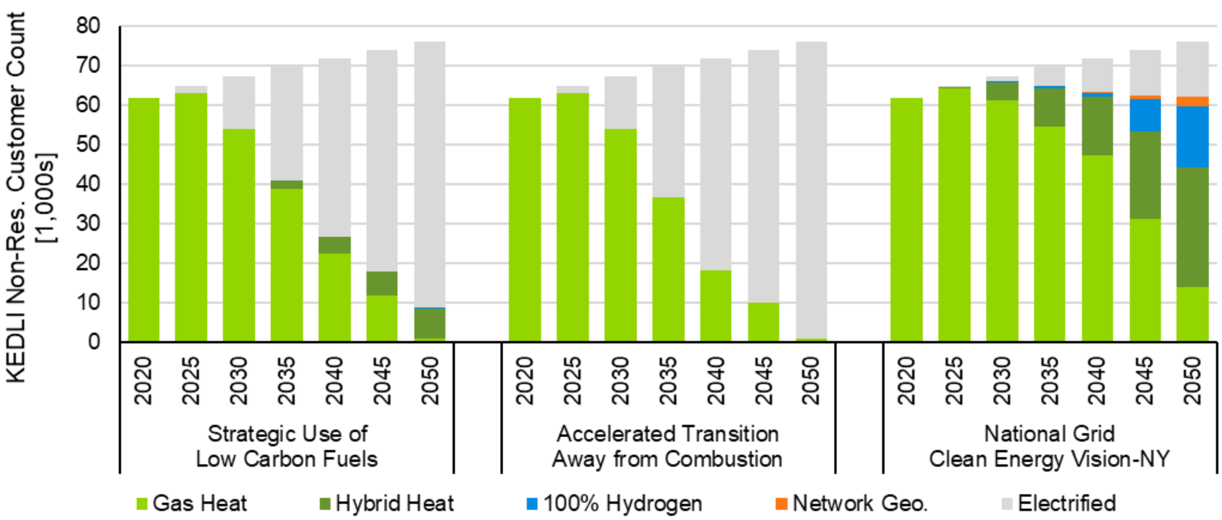
Source: Guidehouse analysis

Figure 3-7. KEDLI Customer Count Forecasts, 2020-2050

(a) KEDLI Residential Customer Counts (thousands)



(b) KEDLI Non-Residential Customer Counts (thousands)



Source: Guidehouse analysis

3.4 Scenario Demand Forecasts

Each scenario illustrates a different vision of the future decarbonized energy system, and Guidehouse developed forecasts of demand for each energy carrier based on the parameters that define each scenario. This section describes how the demand for different energy carriers evolves over time for the buildings and industry sectors.

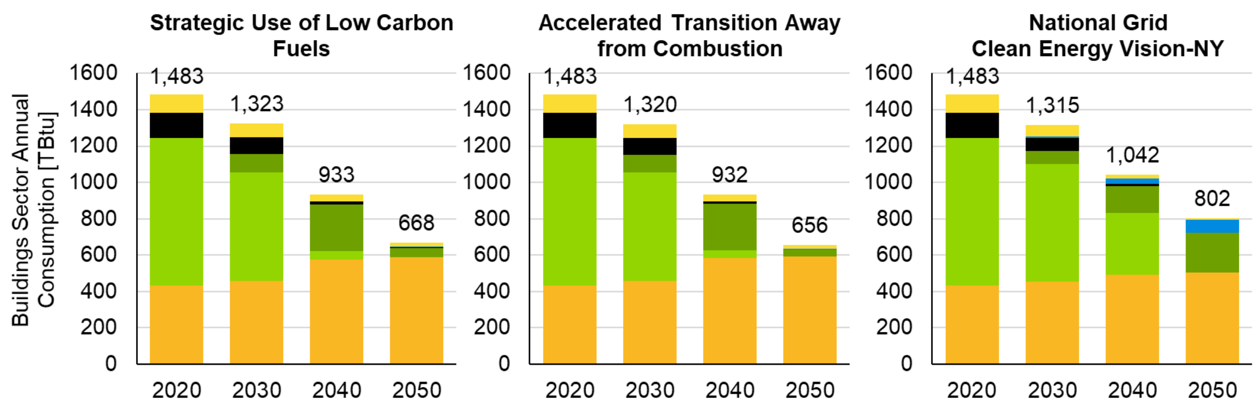
3.4.1 Statewide Energy Demand Forecast

Across all three demand scenarios, statewide total energy demand decreases from 2020 to 2050 by over 40%, largely driven by energy efficiency improvements and electrification (Figure 3-8). Electricity's share of final energy demand grows from less than 30% in 2020 to 80% in 2050 in the Integration Analysis scenarios; in the CEV.NY scenario, electricity accounts for about 60% of final energy demand due to higher usage of hydrogen and RNG, which account for 13% and 20% of total energy demand, respectively.

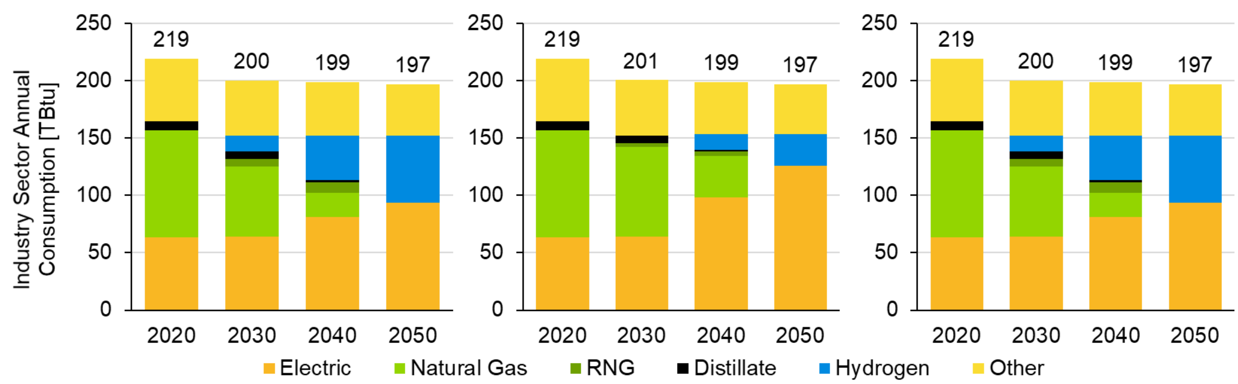
Across all scenarios, statewide end-use gas demand declines significantly, and conventional natural gas usage drops to zero by 2050, with RNG replacing most of remaining gas network building demand building demand and hydrogen replacing most of industrial demand. For buildings, electricity provides the largest share of energy across all scenarios in 2050, with only the CEV.NY scenario projecting sizeable shares of building energy demand from RNG and hydrogen. Industrial energy demand decreases by about 10% relative to 2020. In the Strategic Use of Low-Carbon Fuels scenario and the CEV.NY scenario, electricity accounts for slightly less than 50% of industrial demand in 2050, with hydrogen composing 30% of total demand and other energy sources accounting for the final 20%. In the Accelerated Transition Away from Combustion scenario, electricity accounts for about 65% of total industrial demand while hydrogen only accounts for about 15%.

Figure 3-8. Statewide Energy Demand Forecasts by Sector and Energy Carrier

(a) Buildings Sector Energy Demand Forecasts



(b) Industry Sector Energy Demand Forecasts



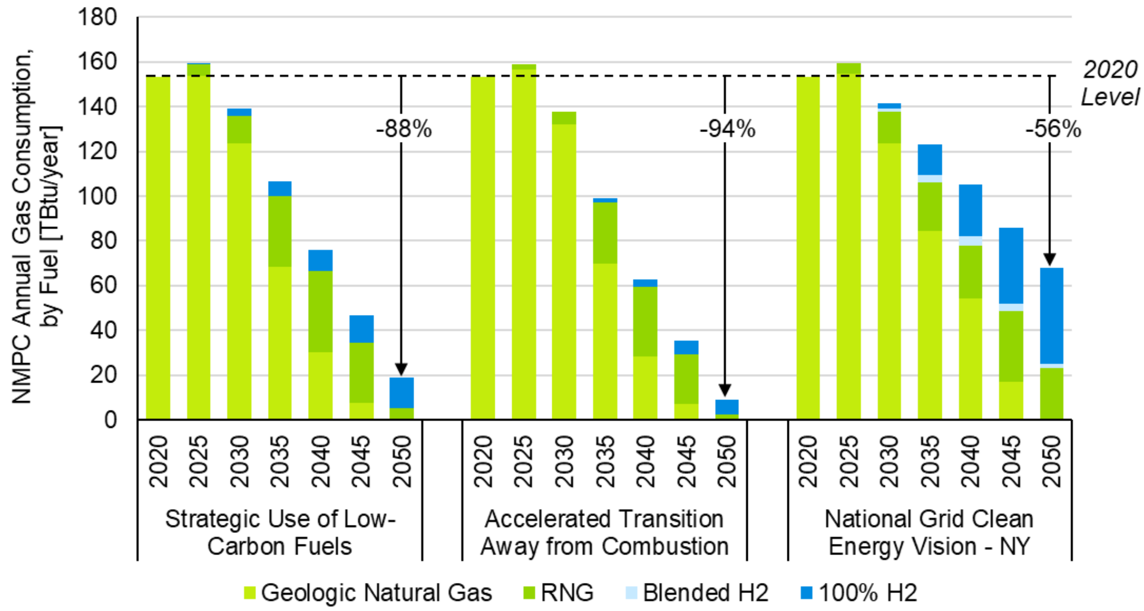
Source: Guidehouse analysis

3.4.2 Operating Company Gas Demand Forecasts

Forecasts of gas demand on National Grid's distribution networks follow a similar trend as statewide gas demand, as shown in Figure 3-9 through Figure 3-11. In all scenarios, methane demand in National Grid territories is projected to increase through 2025 as energy efficiency and electrification interventions begin to take shape. After 2025, each of the three scenarios project a decline in total gas demand, and all scenarios project that demand will shift from geologic natural gas to a combination of RNG and hydrogen fuels. The Integration Analysis scenarios project a steeper decline in total gas demand from 2025 to 2050, with a total demand decline of about 90-95% from 2020 to 2050. The Integration Analysis scenarios project that annual demand for RNG will be higher in the interim years of 2030 to 2045 than in the final study year of 2050.

In the CEV.NY scenario, hydrogen comprises a larger portion of utility customer gas use in Niagara Mohawk territory compared to KEDNY and KEDLI territories in 2050. This is due to Niagara Mohawk's higher proportion of industry sector customers, which are projected to transition to hydrogen use. The CEV.NY scenario projected that methane demand will decline more in the Niagara Mohawk territory than in KEDNY and KEDLI since a higher proportion of Niagara Mohawk's buildings sector customers are projected to fully electrify their energy use.

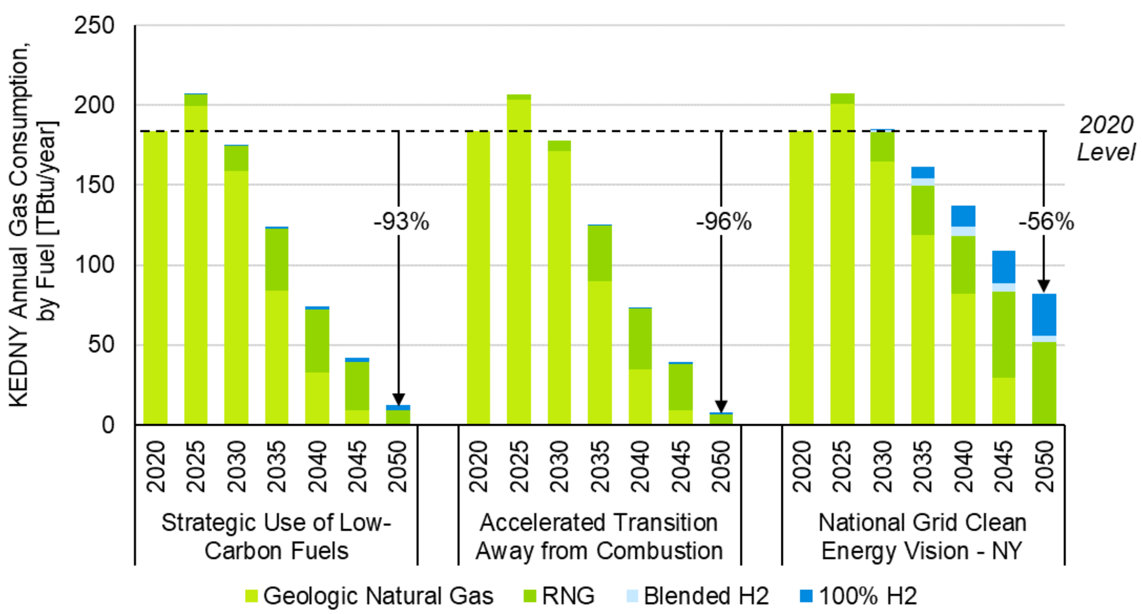
Figure 3-9. Niagara Mohawk Customer Gas Demand Forecasts by Scenario (TBtu/year)



Note: Includes projected gas sales through National Grid's distribution network and does not include gas consumers who receive gas outside of city gate.

Source: Guidehouse Analysis

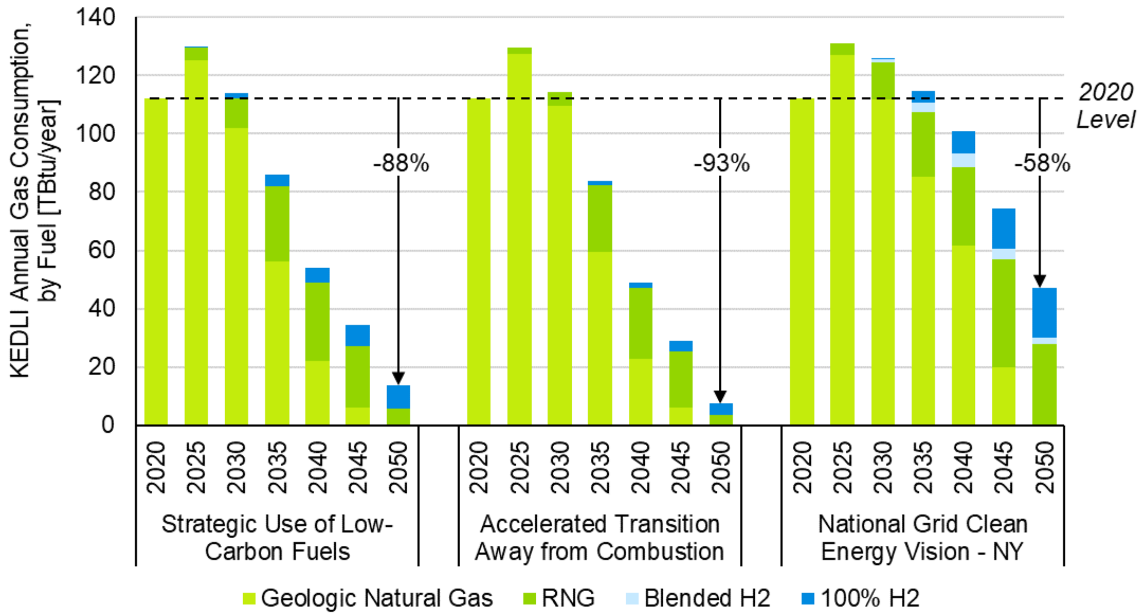
Figure 3-10. KEDNY Customer Gas Demand Forecasts by Scenario (TBtu/year)



Note: Includes projected gas sales through National Grid's distribution network and does not include gas consumers who receive gas outside of city gate.

Source: Guidehouse Analysis

Figure 3-11. KEDLI Customer Gas Demand Forecasts by Scenario (TBtu/year)



Note: Includes projected gas sales through National Grid's distribution network and does not include gas consumers who receive gas outside of city gate.

Source: Guidehouse Analysis

This analysis projects that in the CEV.NY scenario, the total annual demand for RNG from National Grid's New York operating companies will be 103 TBtu/year in 2050. This represents 4.7% of the "high supply" estimate of potential RNG supply from Eastern U.S. states, described in Section 2.5.2.3.[92]

[92] In 2020, National Grid's gas sales in NY comprised 7.2% of Eastern US gas sales for Residential, Commercial, Non-Firm Demand Response, and other non-industrial non-power demand. In 2020, National Grid's **total** gas sales in NY comprised 2.4% of **total** natural gas sales in Eastern US states. The number of people living in National Grid's NY territories comprises 3.9% of the population of Eastern US states.

3.4.2.1 Natural Gas Design Day Demand

Natural gas utilities are expected to provide a firm level of service to customers on an extreme cold weather day called the Design Day. The design day establishes the peak gas demand which is the basis for planning gas capacity needs.

National Grid's Gas Load Forecasting Team developed design day demand forecasts through 2050 for the three scenarios. Several scenario definition parameters were used as inputs for this forecast:

- The increasing rate of partial building electrification (i.e., conversion to hybrid heating systems) and increases in energy efficiency improvements will reduce the average per customer demand over time.
- The increasing rate of full building electrification and customer conversions to network geothermal heating and hydrogen gas service will reduce the number of customers receiving gas service over time.

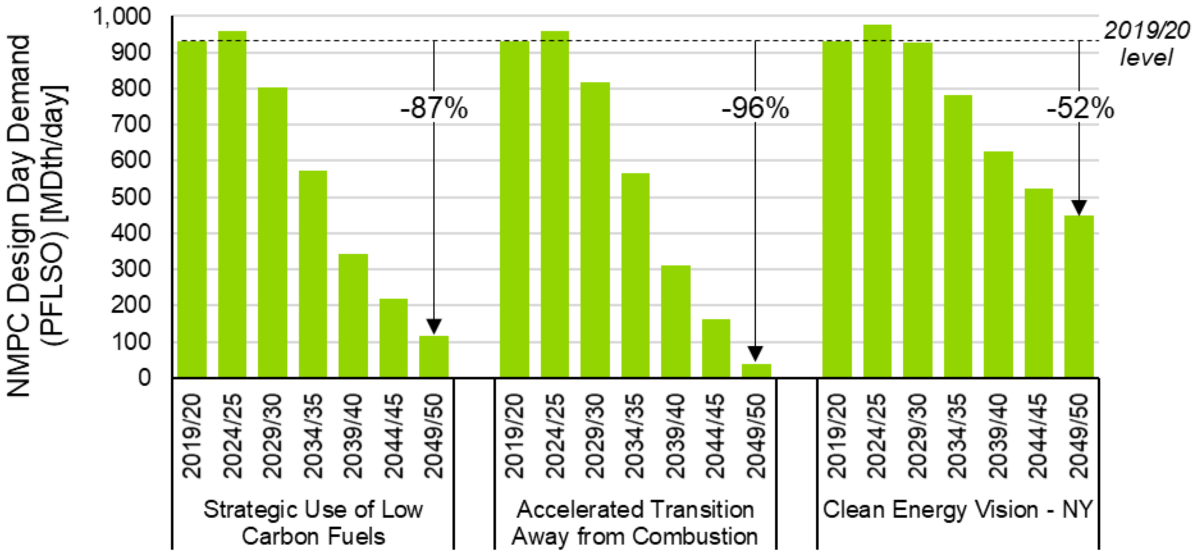
Figure 3-12 and Figure 3-13 present the design day demand forecasts by decade for National Grid's operating companies in Upstate and Downstate New York, respectively. The Upstate and Downstate forecasts have some commonalities. In the Integration Analysis scenarios, design day demand decreases slightly between 2020 and 2030, and then declines sharply through 2050. In the CEV.NY scenario, design day demand does not decline before 2030, and the decline in design day demand from 2030 to 2050 is not as rapid nor as deep as in the Integration Analysis scenarios.

Comparing the Upstate and Downstate design day demand, the trends are similar for the Integration Analysis scenarios. This is because the Integration Analysis scenarios both assume over 90% of buildings are electrified, and the mix of electrification technologies adopted (ASHPs, GSHPs, and hybrid heating) is assumed to be the same across the state. However, in the CEV.NY scenario, Figure 3-12 and Figure 3-13 show different trends for design day demand in Upstate and Downstate territories. The CEV.NY scenario assumed that the portion of customers who fully electrify (using ASHPs or GSHPs) is larger in regions outside of NY City since the lower building density in suburban and rural settings allows for easier access for retrofit and upgrade projects. The CEV.NY scenario assumed that the portion of customers who adopt hybrid heating systems is larger in Downstate NY. This distinction leads to a larger decline in design day demand by 2050 in Upstate NY and a milder decline in Downstate NY.

For the CEV.NY scenario, the design day demand shown below declines by 2050 to a lesser extent than the decline in the annual gas demand presented above in Figure 3-9 through Figure 3-11. For instance, the annual gas demand for KEDNY and KEDLI declines by 57% from 2020 to 2050 compared to a decline of 25% for the Downstate OpCos' design day demand. This illustrates that, in the CEV.NY scenario, gas deliveries are not spread evenly throughout the year but are concentrated during colder periods when hybrid heating customers use their gas-fired heating systems.[93]

[93] The CEV.NY scenario assumes that a large portion of National Grid customers transition to hybrid heating systems. These systems use an electric heat pump to meet heating demand during warmer periods and "shoulder seasons," and they use gas-fired heating systems to meet heating load during colder periods.

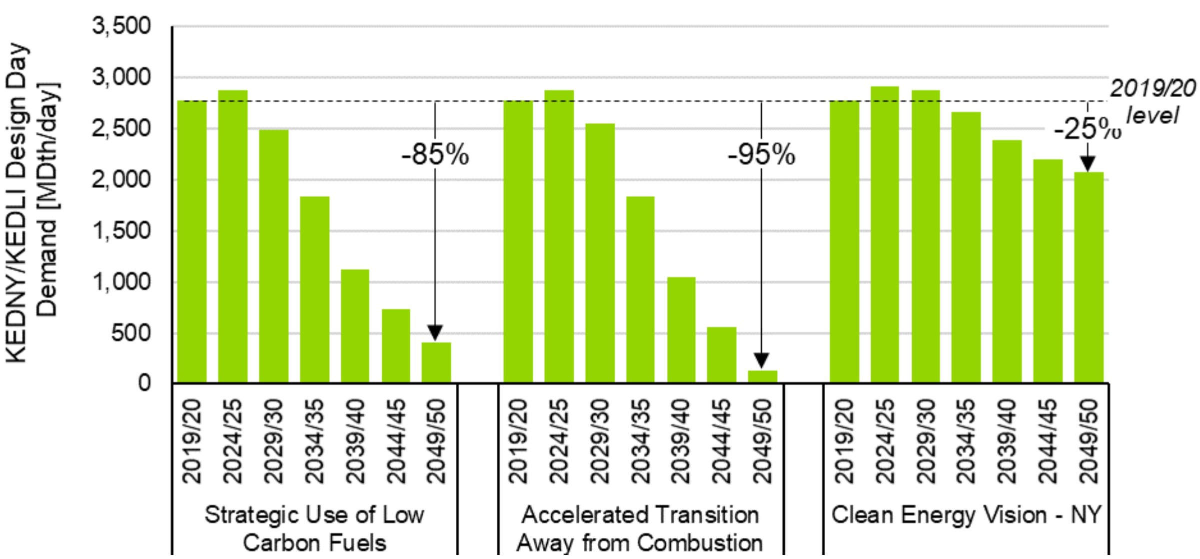
Figure 3-12. Niagara Mohawk Design Day Demand Forecast (MDth/day)



Note: Figures include fossil natural gas, RNG, and pipeline-blended H2 (blended H2 is only used in CEV.NY scenario). Figures do not include gas supplied to customers that convert to 100% hydrogen service. Primary Firm Load Sendout (PFLSO) is those sales classes for which NMPC must plan its interstate pipeline capacity portfolio.

Source: National Grid Gas Load Forecasting

Figure 3-13. Downstate (KEDNY/KEDLI) Design Day Demand Forecast (MDth/day)



Note: Figures include fossil natural gas, RNG, and pipeline-blended H2 (blended H2 is only used in CEV.NY scenario). Figures do not include gas supplied to customers that convert to 100% hydrogen service.

Source: National Grid Gas Load Forecasting

3.4.3 Electricity Peak Demand Forecast

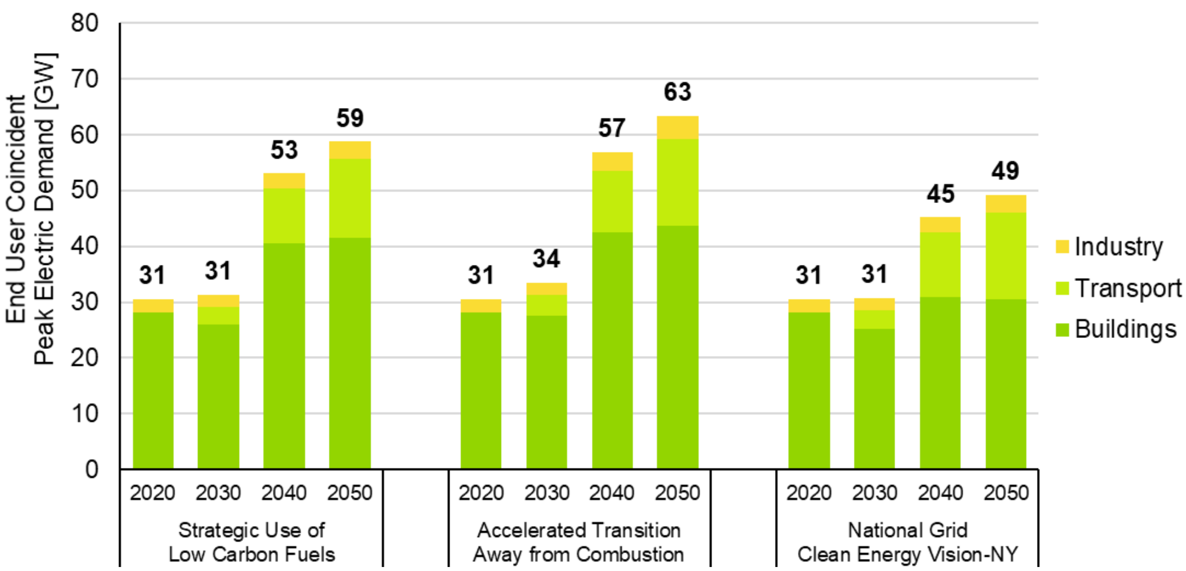
In all scenarios, electrification led to increased peak electricity demand, and a system shift from summer peak to winter peak. Figure 3-14 presents the coincident peak electric demand by decade for the three scenarios, and it shows each energy consuming sector's contribution to coincident peak demand.

A large portion of the increase in peak electric demand is from the transportation sector, as millions of electric vehicles are put in service in New York. This analysis assumed that peak electric demand from the transportation sector is not coincident with peak demand for buildings, due to active management of electric vehicle charging. Even with those interventions, the transportation sector will increase peak loads, and the amount of transportation load growth is similar across all three scenarios.

The peak demand increases the most in the Accelerated Transition Away from Combustion scenario because it is almost fully reliant on electric heat pumps. The Strategic Use of Low-Carbon Fuels scenario has slightly less peak growth, because it assumes a small amount of hybrid heating systems, which help to mitigate peak load. The CEV.NY scenario has the smallest amount of peak growth, because it assumes a higher portion of hybrid heating systems and hybrid systems meet a portion of peak heating load using combustion.

These differences in peak electric demand are important to this study because they affect the amount of new electric generation, transmission, and distribution capacity that is needed, and electric capacity growth impacts the cost of each scenario.

Figure 3-14. Statewide Annual Coincident Peak Demand for End-User (i.e., Direct) Electric Consumption



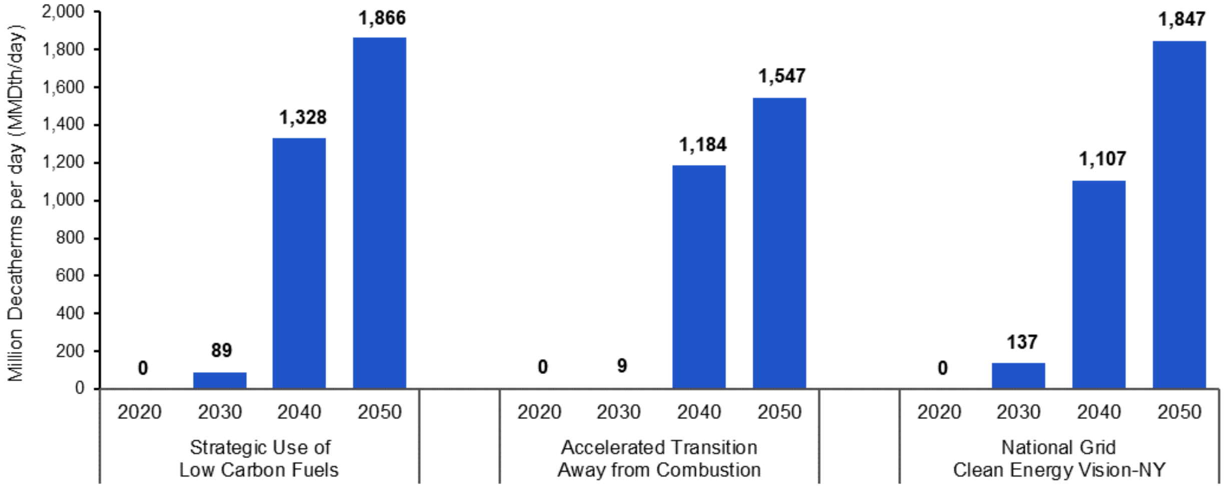
Source: Guidehouse analysis

3.5 Gas Supply Development

Today, New York imports most of the natural gas used in the state. As the state evolves to meet the Climate Act's emissions requirements, conventional natural gas will be replaced by hydrogen and RNG. This provides New York with the opportunity to develop in-state RNG and hydrogen production capacity. All scenarios assume that hydrogen produced in New York is green hydrogen, produced using electrolyzers powered by electricity from renewable sources.

All scenarios project a modest introduction of hydrogen production capacity by 2030, followed by a sharp ramp up in hydrogen production from 2030 to 2050 (Figure 3-15).

Figure 3-15. NY Statewide Hydrogen Production Capacity by Scenario (MMDth/day)



Source: Guidehouse analysis

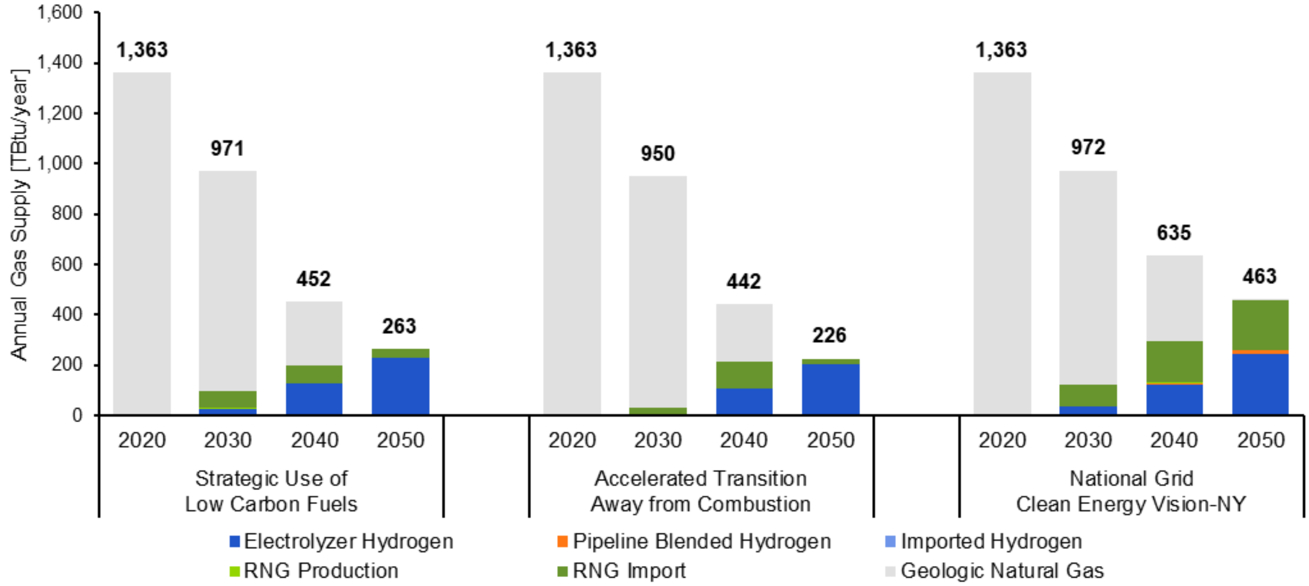
All scenarios projected a decline in annual gas supply from 2020 to 2050 (Figure 3-16). The Integration Analysis scenarios projected an 81-83% drop in gaseous fuel consumption by 2050. The Integration Analysis scenarios also projected that hydrogen will meet most demand for gaseous fuels, with a small amount of demand met by RNG imported from out of state. In contrast, the CEV.NY scenario forecasted a 66% decline in gaseous fuel consumption from 2020 to 2050, with gaseous fuel supplied in 2050 split between green hydrogen and RNG. All scenarios assume that the components of fuel supplied via pipeline distribution networks will shift over time, from 100% geologic natural gas in 2020 to 100% renewable gas in 2050, as described in Table 3-1.

Table 3-1. Composition of Statewide Gas Distribution Network Fuel Supply over Time (Percent by Energy)

Scenario	Strategic Use of Low-Carbon Fuels			Accelerated Transition Away from Combustion			National Grid Clean Energy Vision-NY		
Component	**Geologic NG**	**RNG**	**H_2**	**Geologic NG**	**RNG**	**H_2**	**Geologic NG**	**RNG**	**H_2**
2020	100%	0%	0%	100%	0%	0%	100%	0%	0%
2030	91%	9%	0%	96%	4%	0%	89%	10%	1%
2040	14%	86%	0%	14%	86%	0%	66%	29%	5%
2050	0%	100%	0%	0%	100%	0%	0%	93%	7%

Source: Guidehouse analysis

Figure 3-16. NY Statewide Gas Supply Mix (TBtu/year)



Note: Figure includes gaseous fuels supplied via existing natural gas distribution networks and direct supplies of 100% hydrogen.

Source: Guidehouse analysis

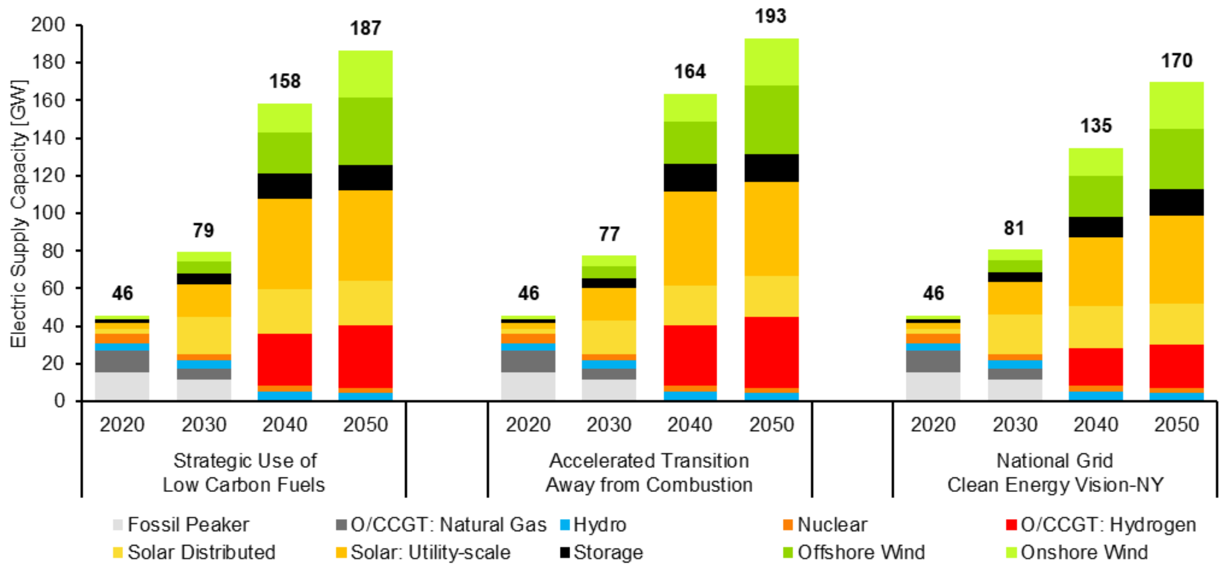
3.6 Electricity Supply Development

To meet the forecasted increase in electricity demand in the coming decades, the statewide nameplate electricity supply capacity is projected to increase over threefold in all scenarios. One driver of this is the high level of electrification across all energy consuming sectors. Another driver of electric capacity growth is the difference in capacity factors between the gas-fired systems in use today and the renewable capacity planned for the future. The electric system will shift from natural gas generators with a high capacity factor to renewable energy sources with a lower capacity factor.

The Accelerated Transition Away from Combustion scenario shows the largest electricity capacity buildout to 2050 while the CEV.NY scenario has the lowest capacity growth of the three scenarios. Across all scenarios, fossil fuel supply capacity is phased out by 2040 to comply with the Climate Act's requirement for a net zero power sector. All scenarios assume the same amount of hydroelectric and nuclear generation capacity.

The CEV scenario needs less buildout of electricity storage and gas turbine generators. These are peaking resources that are needed more in the Integration Analysis scenarios to handle the higher peak demands resulting from full building electrification in those scenarios.

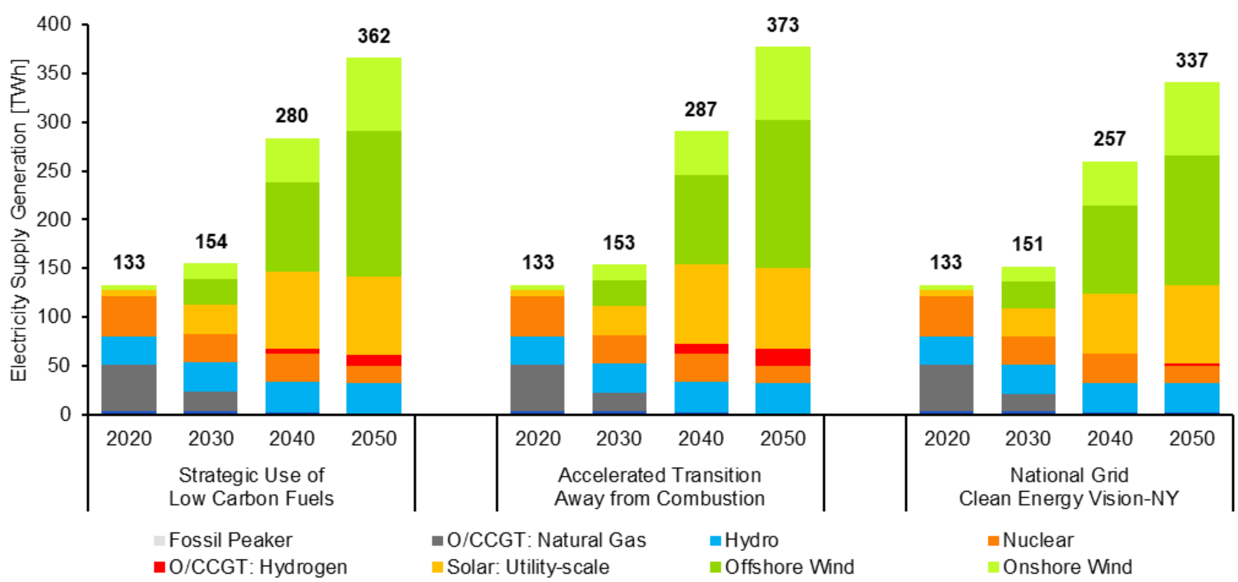
Figure 3-17. Statewide Electricity Supply Capacity (GW)



Source: Guidehouse analysis

In terms of the electricity generation mix, the amount of electricity produced annually is projected to increase over 250% from 2020 to 2050 in all scenarios (Figure 3-18). Most new generation in 2030 and beyond is from solar and wind generation. The Integration Analysis scenarios show more hydrogen gas turbine generation in 2040 and 2050. As noted above, gas turbines are a peaking resource needed to meet the higher coincident peak demand resulting from full building electrification.

Figure 3-18. Electricity Generation Mix (TWh)

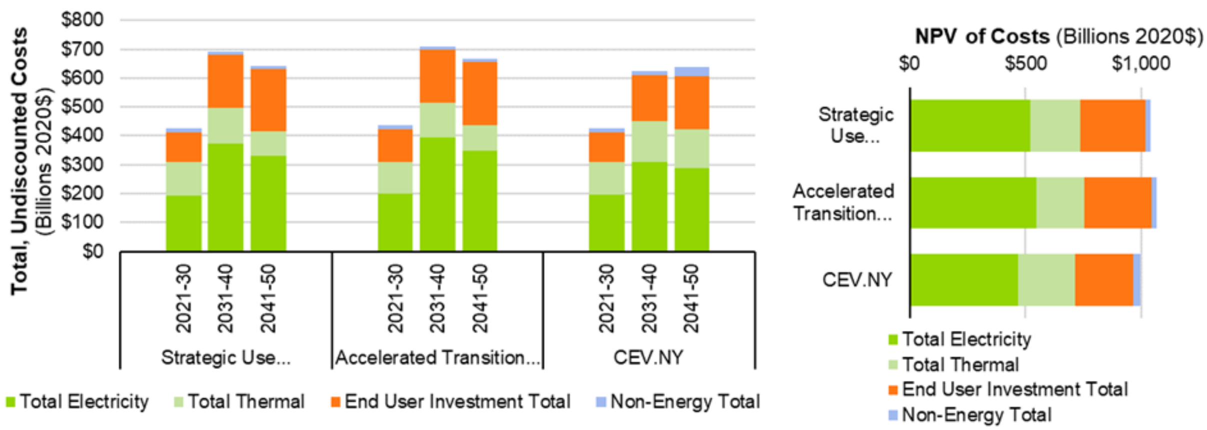


Source: Guidehouse analysis

3.7 Costs

A comparison of the total cost of each modeled scenario is shown below. In total, the CEV.NY scenario has lower costs than the other scenarios, driven largely by lower end-user heating equipment costs and avoided electric infrastructure costs, though a portion of this cost savings is offset by relatively greater investment the thermal network and in non-energy investments.

Figure 3-19. Total Analyzed New York State Expenses by Scenario



Note: See following sections for breakdown of costs by category, and Section 2.6 for description of cost estimation. Upfront plus ongoing costs incurred between 2020-2050 included. Net present value (NPV) assumes real discount rate of 3.6%.

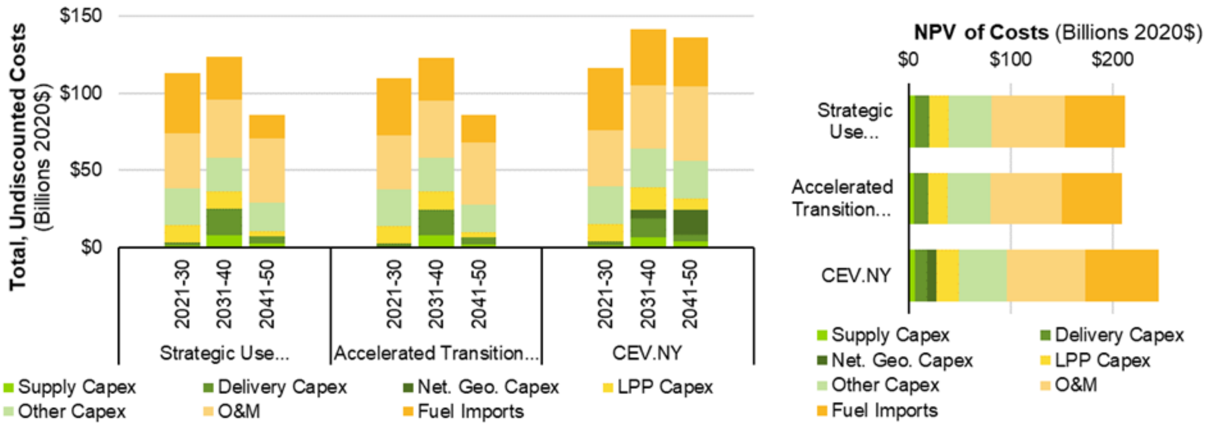
Source: Guidehouse analysis

The following subsections provide further detail on the costs listed above, as well as list the costs from the perspective of various entities within New York State.

3.7.1 Statewide Energy System Costs

Comparing the thermal system costs across scenarios, the CEV.NY scenario includes relatively greater investment later in the analysis period, primarily in the form of networked geothermal. In addition to continued O&M and fuel import costs, as well as slightly higher leak-prone pipe replacement costs, the CEV.NY scenario calls for more thermal system costs than the Integration Analysis scenarios. Note that this study does not consider the incremental costs of decommissioning thermal network segments that may vary by scenario. These would include the cost of removal of system pipe and related equipment where necessary, environmental cleanup costs, regulatory costs, and costs associated with maintaining the safe and reliable operation of remaining network segments during the decommissioning process.

Figure 3-20. Total Thermal System Costs

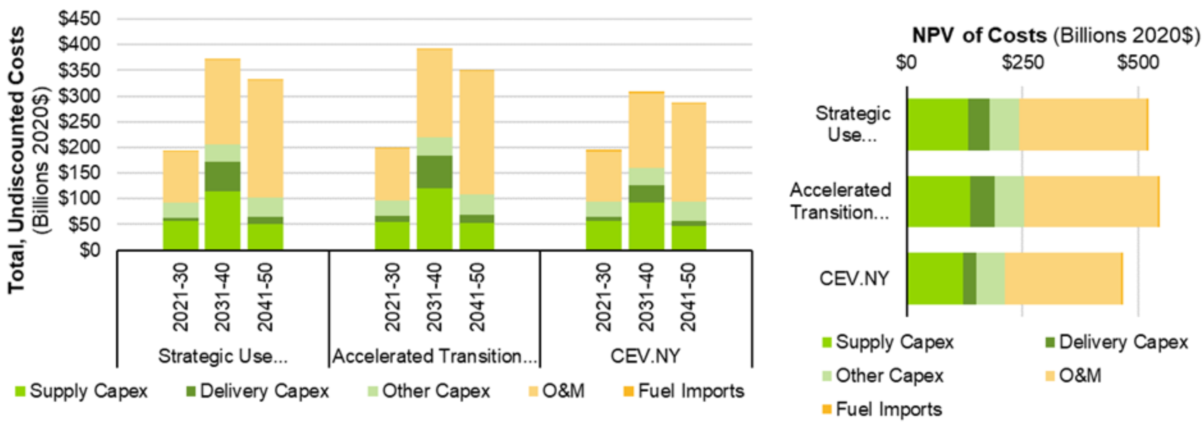


Note: Upfront plus ongoing costs incurred between 2020-2050 included. Thermal network fuel imports include cost of imported NG/RNG/H2 used for electric generation. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

While the CEV.NY scenario calls for greater investment in the thermal energy network, the Integration Analysis scenarios call for greater electric energy network costs. This is primarily driven by increased delivery capital expenses necessary to meet increased electric peak demand, which includes transmission and distribution capacity.

Figure 3-21. Total Electric System Costs



Note: Upfront plus ongoing costs included. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

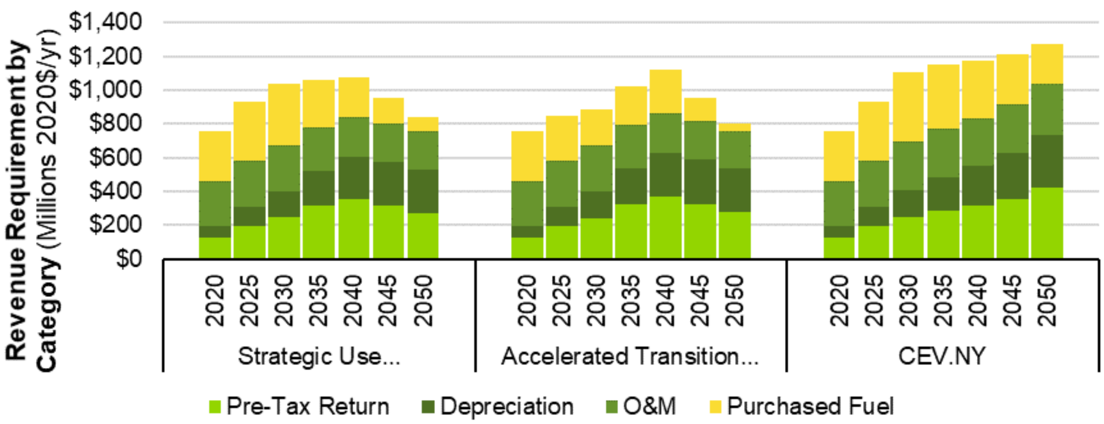
3.7.2 Thermal System Revenue Requirements by Operating Company

As identified in the prior section, investment in the thermal network is estimated to continue to be necessary in each scenario through 2050. Under the current regulatory structure, those investments are depreciated annually over their lifetime. The utility then receives some approved rate of return in each year on the remaining, undepreciated asset base. Those costs, in addition to other annual costs like O&M and fuel purchases, comprise the utilities' revenue requirement, which simulates the total revenue utilities receive each year from delivering energy. The following graphs present this value for select years for each National Grid NY gas service company in each scenario.

Note that these values assume that the current approved straight-line depreciation rates persist throughout the analysis period. If depreciation rates are somehow accelerated in future regulatory proceedings, the "levelized cost" columns of the charts below would likely be higher in the medium term and lower in the longer-term. For example, the Companies' analysis filed under Case 20-G-031 found that, under a High Electrification scenario that is similar in characteristics to the Integration Analysis scenarios, annual depreciation expense may need to be at least 50 percent higher than under the current business-as-usual approach.

For each of the service companies, the Integration Analysis scenarios see revenue requirements decline around 2040, reaching current levels by 2050. In the CEV.NY scenario, revenue requirements stop growing around 2040, but do not decrease in the same way as the Integration Analysis scenarios.

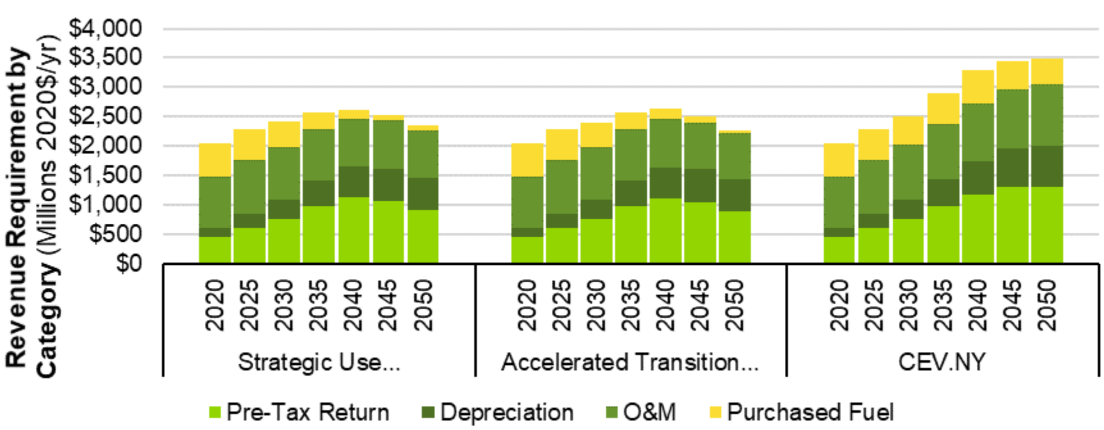
Figure 3-22. Annual Revenue Requirement – NMPC Gas



Note: Assumes current approved straight-line depreciation rates, WACC, and tax rates persist throughout analysis period. "Purchased Fuel" line item also includes fuel supplied to transport-only commercial and industrial (C&I) customers.

Source: Guidehouse analysis

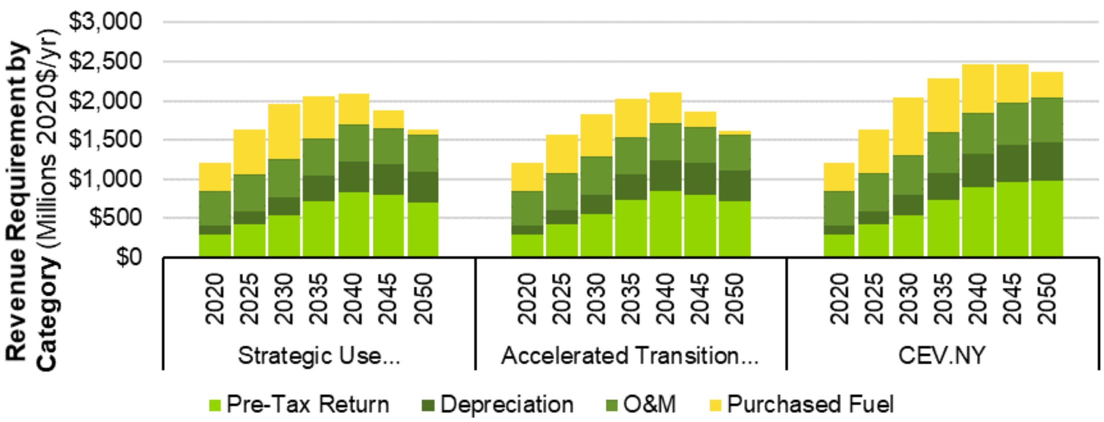
Figure 3-23. Annual Revenue Requirement – KEDNY



Note: Assumes current approved straight-line depreciation rates, WACC, and tax rates persist throughout analysis period. "Purchased Fuel" line item also includes fuel supplied to transport-only C&I customers.

Source: Guidehouse analysis

Figure 3-24. Annual Revenue Requirement – KEDLI



Note: Assumes current approved straight-line depreciation rates, WACC, and tax rates persist throughout analysis period. “Purchased Fuel” line item also includes fuel supplied to transport-only C&I customers.

Source: Guidehouse analysis

3.7.2.1 Normalized Revenue Requirement Metrics

Dividing the identified annual revenue requirement by customer count or by delivered energy provides an indication of what customers will effectively pay as part of the thermal network in each scenario under the current regulatory environment. The revenue requirement per customer reflects an illustrative trajectory of customers’ annual bills under the current regulatory environment, averaged across all customer types and usages. The revenue requirement per unit of thermal demand reflects the trajectory of the delivered price of thermal energy under the current regulatory environment, again averaged across all customer types.

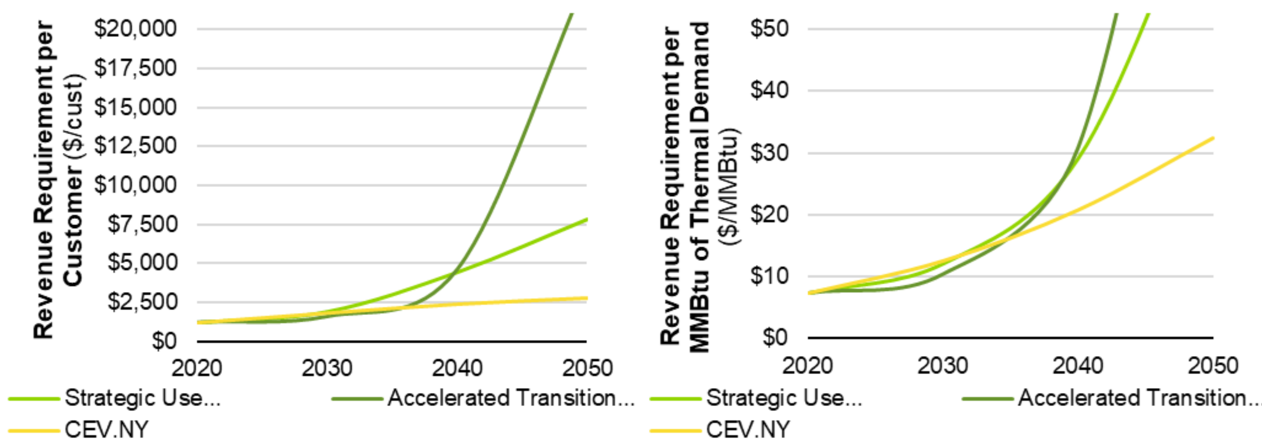
It is important to call out that these figures represent a projection of unitized thermal energy network costs under the current regulatory environment – they do not reflect any potential changes to depreciation accounting for thermal utilities in New York State or any other policies and targeted approaches to mitigate long-term affordability challenges. These values also do not assume any cost sharing across energy systems (i.e., the denominators only include thermal system participants and demand in each year). Potential reforms to address long-term gas network affordability are addressed in Section 1.

The trajectories below demonstrate the importance of such reforms, as well as the relative magnitude of the affordability challenge across scenarios. While all scenarios suggest growth in average unit costs absent regulatory changes, these costs are highest in the Accelerated Transition Away from Combustion Scenario (“CAC #3”), which has the least number of remaining thermal customers and the least annual thermal demand later in the analysis period, which leads to the highest unitized thermal energy system costs. The affordability challenge is reduced in scenarios that retain a greater degree of gas network utilization. However, while average unit costs are lowest in the National Grid CEV, they still suggest a 3-5x increase in the thermal energy price over the analysis period on an inflation adjusted basis, indicating that across any decarbonization pathway there will be a need for reforms to support long-term gas network affordability.

Reforms to advance recovery of depreciation expense would have some impact on the trends shown below, but particularly for a high-electrifications scenario most similar to the Accelerated

Transition scenario, would have a limited impact on the trajectory over time. The Companies' November 2022 filing found that although alternative depreciation approaches would increase near-term revenue requirements per customer and lower them over the long-term, revenue requirements per customer would still be expected to grow exponentially for most methods given the assumed customer departures.[94] The study also found that for the Clean Energy Vision scenario as analyzed therein, a units of production approach to depreciation would result in revenue requirements per customer that most closely align with business-as-usual expectations.[95] Reforms to depreciation approaches would impact the projected trends in normalized revenue requirements.

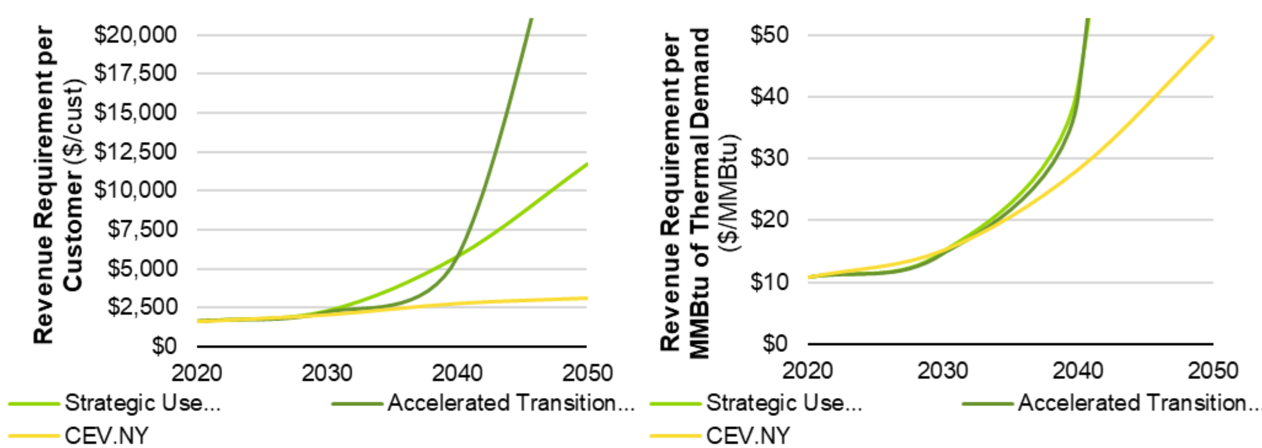
Figure 3-25. Normalized Revenue Requirements – NMPC Gas



Note: Annual revenue requirement, as described in Section 3.7.2, divided by total thermal customer count and total delivered energy. Inflation adjusted (2020 dollars).

Source: Guidehouse analysis

Figure 3-26. Normalized Revenue Requirements – KEDNY



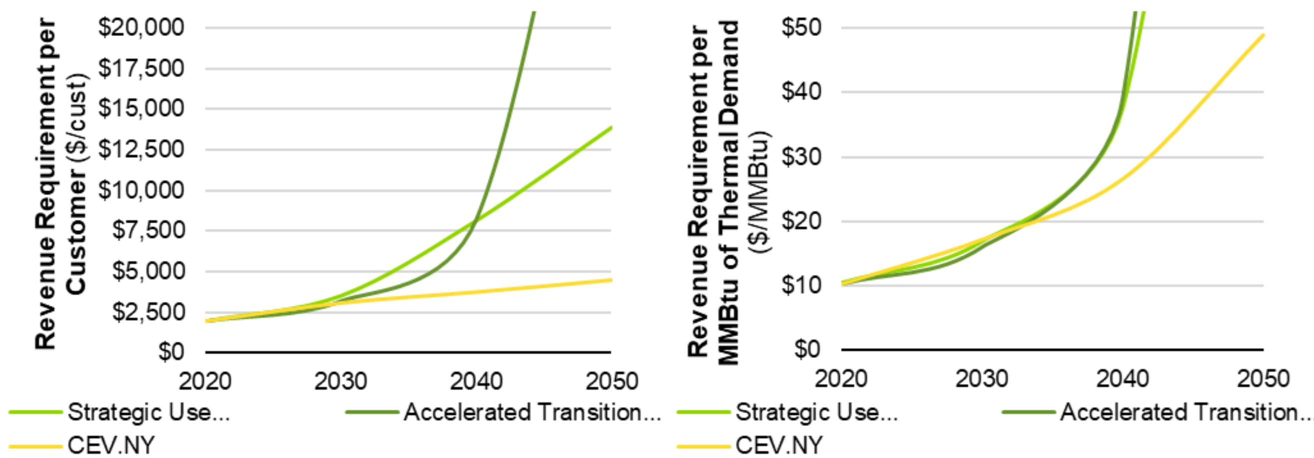
Note: Annual revenue requirement, as described in Section 3.7.2, divided by total thermal customer count and total delivered energy. Inflation adjusted (2020 dollars).

Source: Guidehouse analysis

[94] The analysis evaluated a Units of Production approach and two straight-line scenarios that would recover all rate base by 2050 or rate base associated with new investments by 2050, respectively.

[95] P. II-36

Figure 3-27. Normalized Revenue Requirements – KEDLI



Note: Annual revenue requirement, as described in Section 3.7.2, divided by total thermal customer count and total delivered energy. Inflation adjusted (2020 dollars).

Source: Guidehouse analysis

3.7.3 Customer Costs

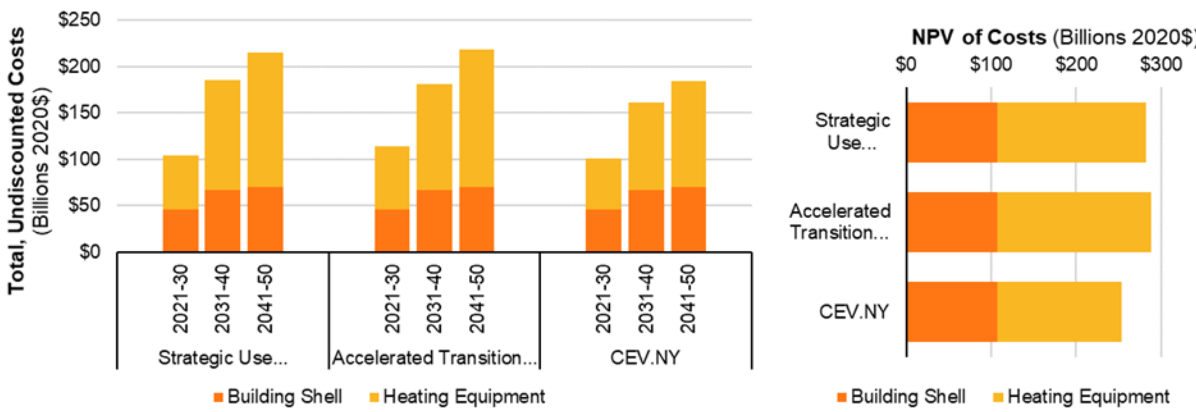
This analysis considered two key costs to customers of the energy transition: (1) investment in heating system equipment and efficiency measures, and (2) customer bill impacts of space heating. That information is presented for each scenario in the following section.

3.7.3.1 Customer Equipment Investment Costs

The total cost of building shell upgrades and new heating equipment assumed in each scenario across NY State is shown below. Note that these costs exclude any state or federal incentives to reflect total cost to the state; statewide incentives and some portion of federal incentives would in effect be paid for by NY State taxpayers.[96] The CEV.NY scenario has the lowest relative costs, because it calls for less electrification and therefore less heat pump installations, which are assumed to be higher cost over the analysis period.

[96] The extent to which New York State taxpayers are a net contributor or net beneficiary of federal funds such as IRA is unknown, so this analysis assumes it is a wash.

Figure 3-28. Total Customer Investments



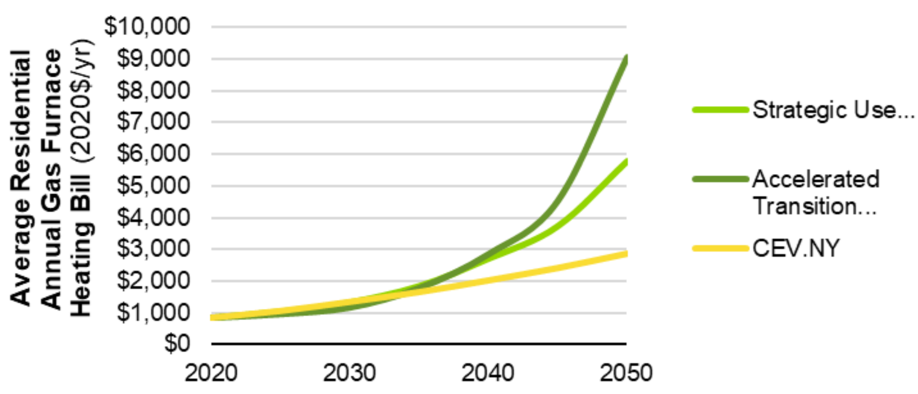
Note: Total upfront costs included (excludes any state or federal incentives). Includes costs to both residential and C&I customers. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

3.7.3.2 Indicative Customer Bill Impacts

Multiplying the thermal energy price in each scenario and region by the assumed average usage of residential gas furnaces over the analysis period yields an estimate of the average annual space heating bill for customers that maintain a gas furnace throughout the analysis period. The following graphs then largely mirror the thermal energy price graphs in Section 3.7.2.1, although the changes are somewhat mitigated by efficiency improvements. The same caveats discussed for those graphs then also apply here; the growth in energy bills around 2040 primarily reflect the impact of the current regulatory environment, which may change by that time.

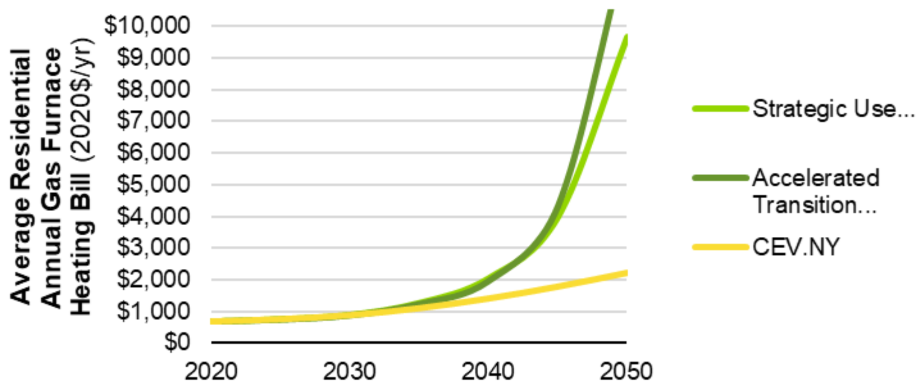
Figure 3-29. Average Annual Residential Gas Furnace Energy Bill – NMPC Gas



Note: Product of delivered thermal energy price as described in Section 3.7.2.1 and average residential usage per customer. Caveats of thermal energy price described above also apply here (i.e., large increase in later years is primarily driven by current regulatory system, which may change). Average residential usage per customer assumed to change gradually over time, whereas individual customers will perform discrete building shell and heating technology efficiency improvements at fixed times.

Source: Guidehouse analysis

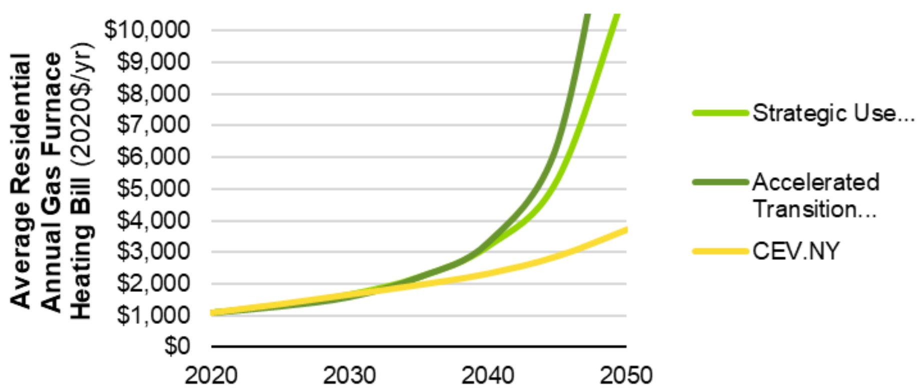
Figure 3-30. Average Annual Residential Gas Furnace Energy Bill – KEDNY



Note: Product of delivered thermal energy price as described in Section 3.7.2.1 and average residential usage per customer. Caveats of thermal energy price described above also apply here (i.e., large increase in later years is primarily driven by current regulatory system, which may change). Average residential usage per customer assumed to change gradually over time, whereas individual customers will perform discrete building shell and heating technology efficiency improvements at fixed times.

Source: Guidehouse analysis

Figure 3-31. Average Annual Residential Gas Furnace Energy Bill – KEDLI



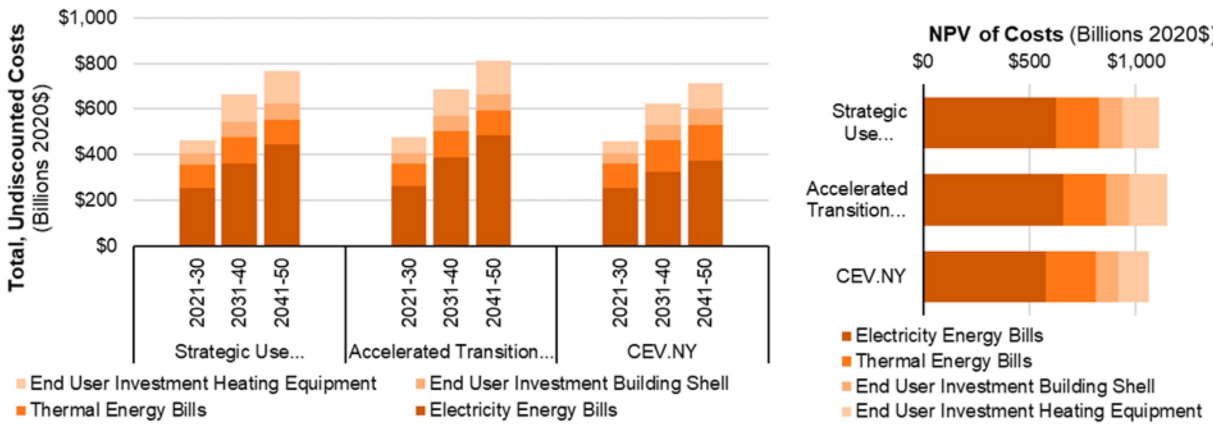
Note: Product of delivered thermal energy price as described in Section 3.7.2.1 and average residential usage per customer. Caveats of thermal energy price described above also apply here (i.e., large increase in later years is primarily driven by current regulatory system, which may change). Average residential usage per customer assumed to change gradually over time, whereas individual customers will perform discrete building shell and heating technology efficiency improvements at fixed times.

Source: Guidehouse analysis

3.7.3.3 Total Customer Costs

Combining the upfront customer investment costs and ongoing customer energy bill impacts yields the total cost to customers, presented below. Electric energy bills are calculated in the same way as thermal energy bills: unitized estimated annual electric revenue requirement times the demand for electricity in each scenario. The CEV.NY has the lowest total cost to customers, due to both the lower cost of heating equipment in that scenario and the lower total energy bills. The CEV.NY scenario shows higher total thermal energy bills, but the relatively higher cost is offset by lower total electric energy bills.

Figure 3-32. Total End-User Customer Costs



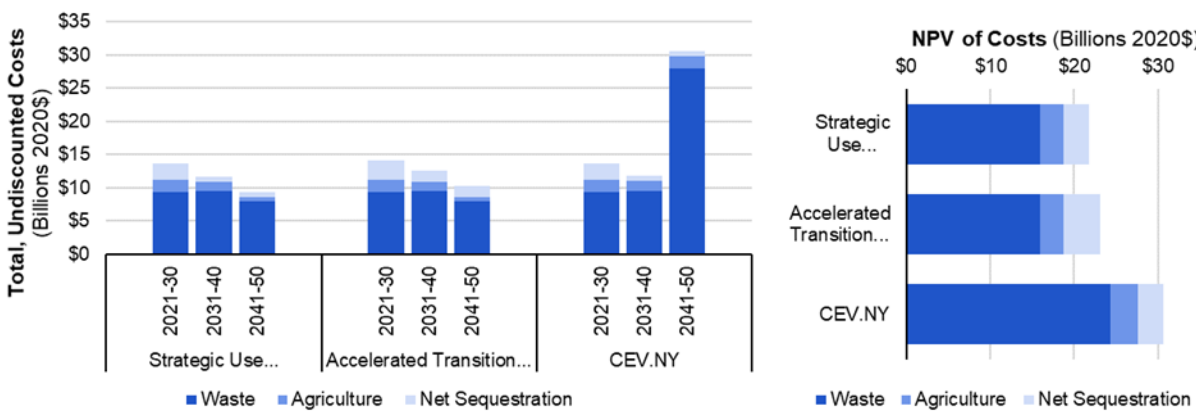
Note: Total upfront costs included (excludes any state or federal incentives). Includes costs to both residential and C&I customers. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

3.7.4 Waste & Agriculture Costs

In addition to energy system costs and customer costs, the cost of necessary emissions reductions in the agriculture and waste sectors were calculated and are presented below. The CEV.NY scenario needs more investment in these sectors after 2040 to reach the necessary emissions savings, leading to higher total costs.

Figure 3-33. Total Agriculture, Waste, and Net Sequestration Costs



Note: Upfront plus ongoing costs included. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

3.8 Sensitivities

The analysis presented in this chapter is predicated on several key assumptions regarding the energy transition. Understanding how these assumptions influence the analysis presented above is then vital to drawing meaningful conclusions. The following section examines the sensitivity of the outputs presented in Section 3.7 to these key assumptions.

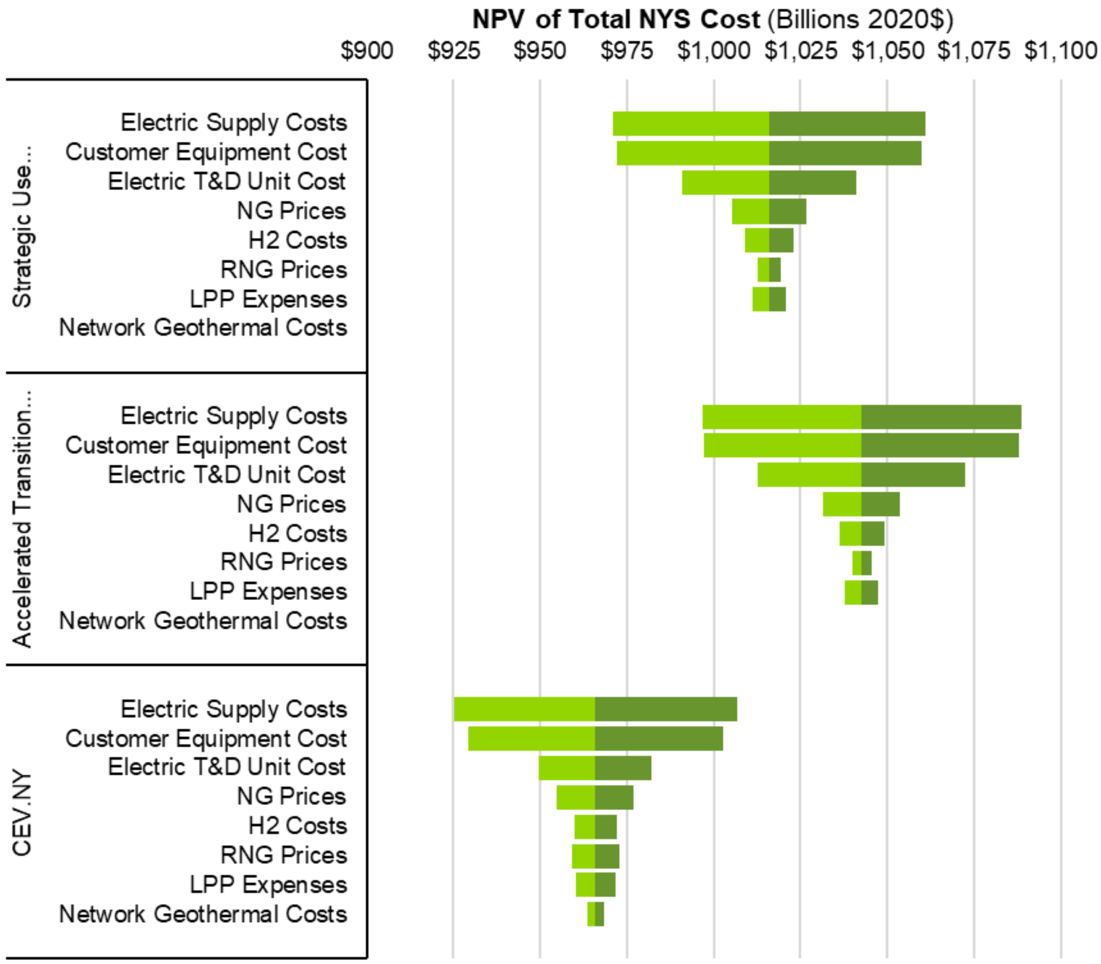
3.8.1 Total Cost Sensitivity

The key output of Section 3.7 listing the total NPV cost to New York state of each solution in Figure 3-19 identifies that the CEV.NY scenario is the least expensive of the three scenarios analyzed in this study. Figure 3-34 below illustrates the change in that total NPV cost if the value for various input assumptions each vary by 25%, individually. Note that this assumes the same level of uncertainty around each assumption, which is useful for depicting the relative importance of assumptions. From that perspective, it is evident that electric supply, transmission, and distribution costs and customer equipment costs assumptions are the most impactful because of their relative contribution to the total cost. This identifies then, for example, that reducing customer equipment unit costs would have a major impact on reducing the total cost of the energy transition.

Note that this chart does not account for differences in relative uncertainty between assumptions. For example, given the relative novelty of widespread geothermal networks, perhaps the uncertainty around network geothermal system costs may be greater than 25%. To that extent, the results of the graph can mostly be extrapolated (within reason) due to the primarily linear nature of how these assumptions are used.

The drivers of these cost variations will likely be exogenous to the energy network, and many will likely be exogenous to New York state (supply chain issues, policy changes, fluctuations in labor and material markets). The cost ranges are also reflective of assumptions regarding availability (i.e., lower availability will increase cost). Variations from baseline assumptions would likely then apply to the same extent to all scenarios. For example, global supply chain issues may lead to higher unit costs of customer heating equipment regardless of the scenario that is being followed.

Figure 3-34. Total Cost NPV Sensitivity



Note: Total cost NPV, with each subcomponent varied by +/-25% (left end of light green bar represents low case, right end of dark green bar represents high case). Network Geothermal Cost assumptions do not impact Integration Analysis total cost because there is not assumed to be significant network geothermal in those scenarios. NPV assumes real discount rate of 3.6%.

Source: Guidehouse analysis

This cost sensitivity reflects the first-order impact of cost sensitivities on each scenario. In practice, higher or lower costs in any given scenario would likely lead to differences in scenario inputs and modeled outcomes. For example, if RNG import prices are much higher than estimated, then that could result in more in-state anaerobic digestion investment or more hydrogen usage, which would fundamentally change the outcomes of the scenarios as presented. This sensitivity does not consider those types of higher-order impacts of cost sensitivities, which could further drive differences or parity between scenarios.

3.8.2 Hybrid Heating Sensitivity

Section 3.7 of this report compared the costs associated with the Integration Analysis scenarios and the CEV.NY scenario and showed that the CEV.NY scenario leads to lower energy system costs and lower customer costs. This is primarily due to the CEV.NY scenario assumptions regarding the high adoption rate of hybrid heat pumps. Guidehouse examined a sensitivity case related to the CEV.NY scenario to examine how further increases in hybrid heat pump adoption would affect forecasts of peak demand and system costs.

Table 3-2 presents building sector assumptions for the CEV.NY scenario and for this sensitivity. As shown previously in Table 2-2 (scenario assumptions) and restated in Table 3-2, the CEV.NY scenario assumes that a 75% of residential housing units and 70% of commercial floorspace have electrified heating by 2050, and that a more than half of these electrified buildings will be served by hybrid heating systems. This sensitivity analysis assumes an increased share of hybrid heating systems such that, in 2050, more than 75% of electrified buildings are served by a hybrid heating system.

Table 3-2. Building Sector Assumptions for CEV.NY Scenario and Hybrid Heating Sensitivity

<table>
<tr><th>Clean Energy Vision-New York</th><th>CEV.NY - Hybrid Heating Sensitivity</th></tr>
<tr><td>75% of housing units are electrified by 2050, split as:
<table>
<tr><th></th><th>NY City</th><th>Non-NYC</th></tr>
<tr><td>Hybrid</td><td>76%</td><td>48%</td></tr>
<tr><td>ASHP</td><td>16%</td><td>39%</td></tr>
<tr><td>GSHP</td><td>8%</td><td>13%</td></tr>
</table>
70% of commercial building space is electrified by 2050, split as: 65% hybrid, 20% ASHP, and 15% GSHP</td>
<td>75% of housing units are electrified by 2050, split as:
<table>
<tr><th></th><th>NY City</th><th>Non-NYC</th></tr>
<tr><td>Hybrid</td><td>86%</td><td>78%</td></tr>
<tr><td>ASHP</td><td>7%</td><td>9%</td></tr>
<tr><td>GSHP</td><td>8%</td><td>13%</td></tr>
</table>
64% of commercial building space is electrified by 2050, split as: 75% hybrid, 11% ASHP, and 14% GSHP</td></tr>
<tr><td colspan="2">Networked geothermal serves 4% of NYC and 8% of non-NYC housing units.

20% of non-residential customers convert to 100% hydrogen heat by 2050.

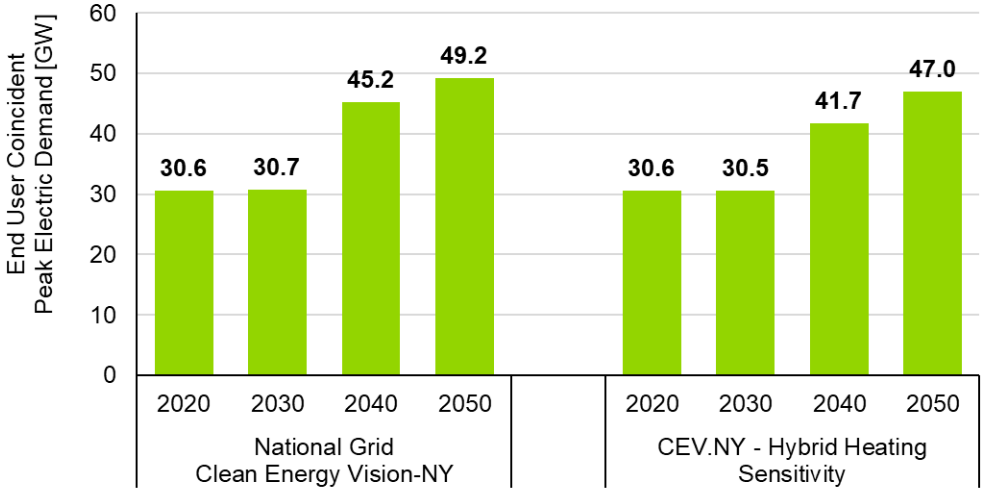
Remaining gas demand is served by methane/hydrogen blend, increasing to 7% hydrogen (by energy) by 2050.</td></tr>
</table>

Source: Guidehouse analysis and NY CAC (December 2021)[97]

Hybrid heat pumps help to mitigate peak electric load growth because they use a fuel-fired heating system to meet customer heating loads during low-temperature periods (when heat pumps operate less efficiently) and during periods of peak demand. Figure 3-35 shows that, relative to the CEV.NY scenario, the sensitivity case with more hybrid heating leads to slower growth in electric peak demand from 2030 to 2050, and an electric peak demand in 2050 that is 2.2 GW (4.5%) lower than the peak demand projected in the CEV.NY scenario.

[97] See: NY CAC (December 2021). "Draft Scoping Plan Appendix G," Sections 2.1 and 5.3. Available at: **https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scoping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.pdf**

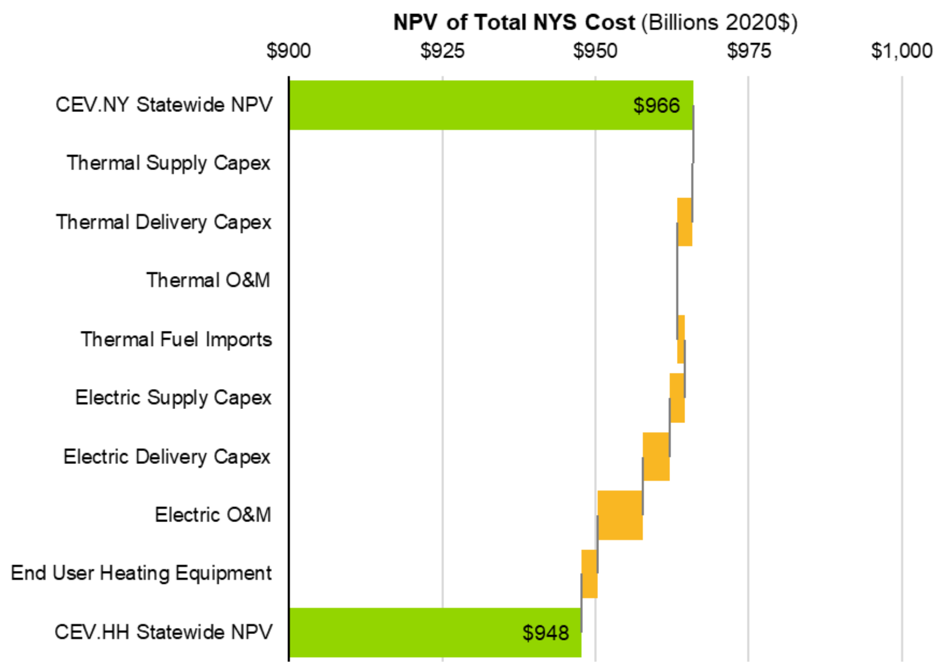
Figure 3-35. Statewide Annual Coincident Peak Demand for End-User (i.e., Direct) Electric Consumption, CEV.NY and Hybrid Heat Sensitivity



Source: Guidehouse analysis

Like the CEV.NY scenario, this hybrid heating sensitivity case meets the Climate Act's GHG reduction requirements, and it does so at slightly lower cost. Figure 3-36 illustrates that, because of lower projected costs for the electric system, end user devices, and other cost categories, the projected NPV for the hybrid heating sensitivity is $18 billion (1.9%) lower than the NPV of the CEV.NY scenario.

Figure 3-36. Total Cost NPV Crosswalk to Hybrid Heating Sensitivity



Note: Total cost NPV. Note: X-axis is compressed to focus on differences.

Source: Guidehouse Analysis

3.9 Other Impacts

This section covers topics relevant to this study that were not quantitatively examined in the analysis, including:

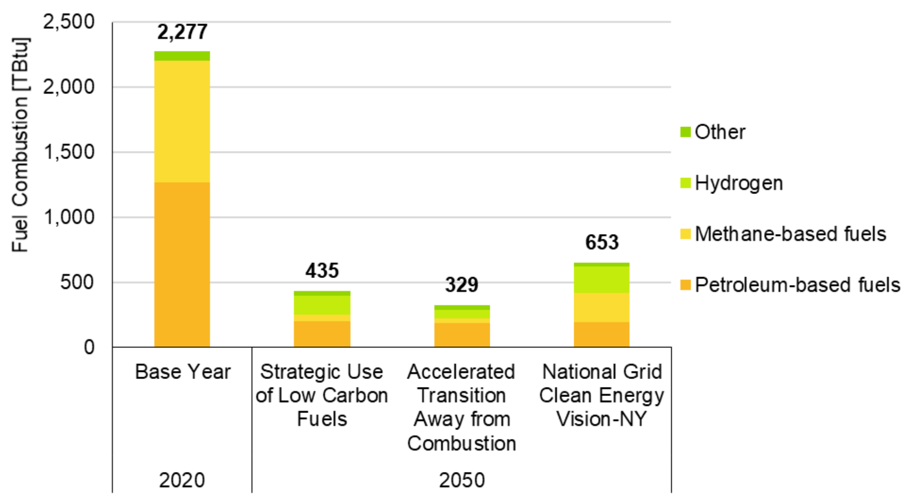
- Public Health Benefits
- Impacts on Disadvantaged Communities
- Energy System Resiliency
- Workforce Considerations
- Local Economic Impacts

1. **Economy-wide CLCPA emission reductions will lead to public health benefits.** Fuel combustion produces pollutant emissions such as PM 2.5 and NOx, which have negative health impacts. All scenarios in this analysis lead to reductions in fuel combustion from buildings, industry, and transportation sectors, as shown in Figure 3-37. Total Fuel Combustion from Buildings, Industry, and Transportation Sectors, **in 2020 and 2050, by Scenario and Fuel Type**

   The Integration Analysis scenarios show the largest reductions in fuel combustion from 2020 to 2050. Of the three scenarios, the CEV.NY scenario has the highest projected amount of fuel combustion remaining in 2050, but the amount of combustion is reduced 71% compared to a 2020 baseline. The reduction in fuel combustion will likely lead to health benefits for New York residents in all scenarios, but quantification of these health benefits is outside the scope of this study.

   It is important to note that reductions in PM 2.5 are the largest source of quantifiable and monetizable public health benefits, due to the association of particulate matter with premature mortality. To that end, the largest driver of health benefits in the CAC Integration Analysis is reduction in residential wood combustion, which is assumed to be reduced equally across all scenarios.

Figure 3-37. Total Fuel Combustion from Buildings, Industry, and Transportation Sectors, in 2020 and 2050, by Scenario and Fuel Type



Note: Does not include electricity generation.

Source: Guidehouse analysis

2. **Impacts on Disadvantaged Communities.** Considerations for DACs is a cornerstone of CLCPA. Key considerations relevant to DACs across pathways include:

    - **Infrastructure**. Each scenario will require new infrastructure to bring clean energy to customers. As energy networks are designed and built, utilities will need to consider how new infrastructure will not unfairly burden disadvantaged communities, and also consider how infrastructure investments can directly benefit communities. Assessment of such impacts and benefits was beyond the scope of this study. Direct input of stakeholders in DACs will be important to informing such assessments.

    - **Emissions**. The economy-wide GHG emission reductions mandated by CLCPA will effectively encourage reductions of other pollutants. These reductions will benefit all New Yorkers, as noted above. The distribution of the impacts will vary by pathway, but the locational analysis was beyond the scope of this study.

    - **Energy efficiency, renewable energy, and electrification programs**. The study assumes a component of achieving the CLCPA targets will be accomplished by substantial expansion of energy efficiency and electrification programs as well as use of renewable energy. Utility and state programs will provide an important mechanism for enabling such end-use investment. The pathways analysis informing this study does not evaluate the locational distribution of these end use investments that will depend on many factors. Discussion of approaches to help support the achievement of the CLCPA requirement that 35% of program investments benefit DACs are considered in Section 5.

3. **Energy system reliability and resiliency.** To reflect the variability of demand loads and supply resources in New York and in neighboring jurisdictions, the LCP model employs four representative seasonal days (winter, spring, summer, fall), two peak days (summer peak and winter peak), and one winter peak day when electric generation from wind resources is limited, and constructs the resources needed to meet demand. As the transition unfolds, and climate change impacts continue to increase challenges associated with energy system resilience, increasing investments to support resilience and maintain system reliability in an increasingly electrified economy are likely to be needed. Such incremental costs were not reflected in this study.

4. **Workforce considerations**. Each scenario assumes there will be sufficient workforce development and training programs to build and maintain the investments undertaken to meet the CLCPA objectives. Limitations in the workforce will likely increase the cost and/or have the potential to delay the achievement of state decarbonization targets if left unaddressed. In addition, decommissioning of substantial segments of the gas network could result in a reduced gas LDC workforce. A workforce assessment for each scenario was beyond the scope of the analysis, though it is reasonable to conclude, given projections of thermal system OpEx and CapEx across scenarios, that more of the LDC workforce would be retained over the long term in the CEV.NY scenario, given both the smaller degree of decommissioning as well as investment in geothermal networks, which provides an opportunity to repurpose the skill set of the workforce The costs and impacts of programs to support LDC workforce transition are not captured in their analysis, but their effectiveness will have implications for local economic impacts.

5. **Local economic impacts**. The study analysis did not directly address local economic impacts, but nonetheless there are several important considerations that could be addressed in a future study, for example:

    - Risk that the rising cost of energy and/or new operational challenges (e.g., to industrial processes) may cause economic activity to shift outside of New York State. This is a consideration across all pathways, but such outcomes may be lower risk in pathways that limit energy-cost impacts and retain flexibility in customer energy choices.
    - Energy production will shift from out-of-state to in-state. Today, much of the energy for vehicles and heating homes comes from outside New York. Each scenario becomes more reliant on in-state resources, whether investing in utility-scale solar and offshore wind for electric generation, or for RNG and hydrogen production. Thus, more of the cost to produce energy could stay within the state, which could have positive effects in other segments of the New York economy.
    - Additionally, increased investments in new infrastructure and energy efficiency will create local jobs, though such job creation may be offset to some degree depending on impacts on the gas LDC workforce. However, these investments, and potential net job creation, would have positive effects on the New York economy.

4. Findings and Implications

This section describes the potential implications of this study for National Grid's customers, the gas network, and New York more broadly. This section starts by summarizing and discussing the study's findings and then outlines potential challenges, risks, and options to address the challenges. The section concludes with a set of recommended next steps for National Grid.

4.1 Study Findings

The key findings of this study are as follows:

1. **To meet the state's climate goals, energy sources across New York's economy must change.** To meet the CLCPA's limits on gross GHG emissions, all scenarios in this analysis assumed that a high degree of electrification will take place in the buildings, industry, and transportation sectors. All scenarios assumed that a portion of energy use in New York will shift from geologic natural gas to RNG and hydrogen. In the Integration Analysis scenarios, energy use in the buildings sector is almost fully electrified, while the CEV.NY scenario complements electrification with the deployment of hybrid heating systems (fueled by electricity and RNG) and pure hydrogen systems. All scenarios assumed that industry sector gas use shifts to a mix of electricity and hydrogen. These scenario design choices influence the demand forecasts for each scenario and provide input to the capacity expansion modeling conducted in this study. All three scenarios modeled in this analysis are compliant with CLCPA emissions limits.

2. **Energy efficiency improvements are needed to achieve New York's climate goals in each of the scenarios studied.** To achieve stated outcomes in the Climate Law, all three scenarios modeled in this analysis assumed a significant improvement to the energy efficiency of buildings, industrial processes, and other end uses of energy. Scenarios assumed that by 2050, energy efficiency will reduce building space conditioning energy needs by 30% and will reduce industrial process energy needs by 40%. As with heating system assumptions, these energy efficiency assumptions are scenario design choices that influence the demand forecasts. This analysis projects that over $100 billion (2020$ net present value) of investment in building retrofits will be needed to by 2050. These improvements and the conversion of fuel-fired vehicles and heating equipment to electric equipment will reduce economy-wide energy use.

3. **Affordability and equity considerations must be prioritized and addressed.** As New York transitions its energy grid, an important consideration for National Grid is to ensure that the change does not unequally benefit certain groups while proving a detriment to others. A variety of factors, including income, location, home age, surrounding environment, and access to information can all influence whether certain groups are willing and able to transition from gas to electricity; higher-income households will likely transition to electrification more quickly due to their ability to afford the upfront costs of electric heating equipment and efficiency upgrades. Absent policies and measures to assist low-income and DACs with the energy transition, the customers remaining on the gas system are therefore more likely to be low-income and disadvantaged communities (DAC) households that, barring regulatory intervention, will be left to pay higher rates for gas system maintenance due to fewer customers on the system. These issues present notable challenges that must be thoughtfully approached by policymakers, regulators, and utilities to ensure that the benefits of the transition are equitably distributed across

the entirety of the state's population and that at least 35% of benefits of clean energy investments accrue to disadvantaged communities. Furthermore, when new energy infrastructure development is considered in DACs, enhanced efforts and stakeholder engagement may be needed to ensure that adverse impacts are minimized and that community benefits are maximized.

4. **All scenarios require significant investment in electricity infrastructure.** New York's electricity supply capacity is projected to increase over threefold in all scenarios due to several factors: (1) High rates of electrification in all energy-using sectors will lead to increased peak electricity demand, requiring new generation capacity. (2) The shift from natural gas-fired electric generation resources (with relatively high capacity factors) to intermittent renewable resources (with lower capacity factors) will need an increase in nameplate electricity generation capacity. All three scenarios also project a scale up of electric T&D infrastructure and energy storage capacity.

5. **The energy transition will be costly, but relative to other scenarios a diversified approach to building sector decarbonization offers opportunities to lower energy system and customer costs.** A large amount of investment will be needed to extend and upgrade New York's energy systems, to retrofit customer buildings, and to replace energy consuming appliances. This analysis estimates the net present value of the energy transition costs from 2020-2050 will range from $0.95 trillion to $1.05 trillion. Compared to the Integration Analysis scenarios, the CEV.NY scenario will have lower total NY State system costs due to lower energy system costs and more diverse investment that will occur across sectors and later in time. The CEV.NY scenario will also rely less on investment in customer-side heating equipment conversions than the Integration Analysis scenarios.

6. **Renewable gas (RNG and hydrogen) will have a role in all scenarios.** The Climate Act's emissions requirements cannot be achieved cost-effectively through electrification alone. Low- and zero-carbon gases like RNG and hydrogen will play a role in GHG emissions reductions, particularly in sectors such as heavy transportation or certain industrial processes that will be challenging to decarbonize through electrification. RNG may be used as a drop-in replacement for geologic natural gas that is distributed today to progress gas network decarbonization. Dedicated hydrogen infrastructure will be necessary to connect hydrogen producers to customers who convert to pure hydrogen service.

7. **Coordination across energy systems will be necessary to transition quickly and at scale.** Such coordination is essential on multiple fronts to accelerate market adoption towards decarbonization. First, coordinated gas and electric system planning will be necessary to advance targeted electrification and optimize infrastructure investments. Second, customer adoption of hybrid heating technologies provides an opportunity for utilities to develop strategies to efficiently utilize both gas and electric infrastructure and manage peak demand. Finally, electricity will be used to produce green hydrogen supply, which will also be critical in meeting peak electricity demand through hydrogen-fired gas turbines.

8. **A strategy that incorporates hybrid heating systems can mitigate electric peak demand growth.** All scenarios project an increase in electric peak demand. Peak electric demand is projected to double by 2050 in the Integration Analysis scenarios, compared to a 60% increase in peak demand in the CEV.NY scenario. Coincident peak

electric demand grows less in the CEV.NY scenario than the Integration Analysis scenarios due to increased adoption of hybrid heating systems. As a result, the CEV.NY scenario entails roughly 10% less investment in new electric generation capacity and roughly 40% less investment to build out electric T&D than the Integration Analysis scenarios.

9. **Regulatory and policy reforms will be needed to maintain reasonable gas utility rates for customers.** In all scenarios, gas customer counts and delivery volumes are projected to decline. Total gas use and customer counts decline less in the CEV.NY scenario, which repurposes existing gas infrastructure to deliver renewable, low-carbon gas. Under the current regulatory environment, with no cost sharing across energy systems, per therm or per customer thermal system costs begin to grow significantly starting around 2040. If the energy transition described in the findings above is not accompanied by a regulatory transition, then gas utilities' normalized revenue requirement per customer is projected to increase at least threefold. Policy will need to shape who pays for the energy transition and define how costs are socialized while protecting disadvantaged communities.

10. **Combustion generation will maintain a critical role in New York's electricity system.** Today, natural gas turbines support electric system reliability by serving as a dispatchable resource. In a CLCPA-compliant future, all scenarios project that hydrogen-fired turbines will be used to meet peak demand and ensure system reliability. These peaking resources will be critical during long periods with little or no electricity generation from wind. Without hydrogen-fired generation, it will be more difficult to achieve a net zero electricity system. A greater amount of combustion generation will be needed in scenarios with greater degrees of space heating electrification.

4.2 Challenges, Risks, and Options to Address

Many challenges will need to be addressed under all scenarios to achieve CLCPA targets. These challenges, and potential options to address them, are discussed in this section and summarized in Table 4-1.

Table 4-1. Challenges and Options to Address Challenges

	Challenge / Risk	Options to Address
Demand-Side Feasibility	- Pace of customer heating equipment turnover versus pace of necessary heating equipment adoption - Barriers to building shell and efficiency installation - Customer willingness/ability to electrify Limitations on supply chain & HVAC workforce	- **Coordinated, geotargeted customer programs** (e.g., demand-side management and heat electrification) - Increased funding of programs to support **building envelope improvements** and adoption of **heat pump technologies,** including government and utility-sponsored **customer incentive programs** - **Workforce training programs**
Supply Side Feasibility	- Siting, permitting, and construction of new electric renewable generation, transmission, and distribution facilities - Pace of necessary expansion of electric transmission, distribution, and storage - Limitations on supply chain & power sector workforce	- **Address siting and permitting challenges** that may be driven by local, state, or federal restrictions or requirements - **Regional planning and coordination** for large transmission projects that cross state or international borders - Accelerate **funding, programs** to support clean energy workforce development
Customer Impacts / Affordability / Equity	- Upfront cost of efficiency and heating equipment upgrades - Increased cost of space heating bills in the short-term for electric heating customers, and in the long-term for thermal customers - Disproportionate impact on low-income customers - Equity and compounding challenges	- **Modified depreciation approaches** to advance recovery and balance near and long-term affordability - Longer-term **socialization of gas network costs** (e.g., electric utility-funded exit fee) - Development of **energy transition equity programs**
Energy System Considerations	- Enhanced coordination across energy systems - Avoidance of gas network costs requires targeted electrification - Procurement of renewable fuels - Legal obligations and regulatory coordination	- **Pilot coordinated gas/electric planning** to assess opportunities to avoid costs - **Clean fuel standard** for thermal energy service to gas distribution customers that includes low-carbon or carbon-free resources (RNG, green hydrogen, networked geothermal) - Broadening of **procurement standards** to include renewable fuels and enable long-term contracting to support project development - **Rate restructuring** to better align recovery of fixed, volumetric costs - Regulatory changes to encourage alternatives to gas system - Alignment of demand-side management and electrification incentives with expected benefit
Technology Readiness and Scalability	- Regulatory and market acceptance of newer technologies (e.g., RNG, hydrogen) - Feasibility of deployment and coordination for network geothermal projects - Scalability of present and future commercial technologies	- Fund and deploy **technology demonstrations and pilots**, leveraging federal funding opportunities where possible - Clarify **utility role** in delivering RNG

Source: Guidehouse

4.2.1 Demand-Side Feasibility

Each of the analyzed scenarios relies on significant customer-sited adoption of energy efficiency measures and efficient heating technologies to yield demand profiles that can be served in a CLCPA-compliant manner. In addition to the customer cost of these upgrades, which are discussed in Section 4.2.2.1, there are several practical and logistical challenges that would need to be addressed, as described below.

4.2.1.1 Challenges

Some of the demand-side challenges are described below:

- **Pace of customer heating equipment turnover versus pace of necessary heating equipment adoption.** Customers generally replace their existing heating equipment when it reaches the end of its useful life. Assuming HVAC equipment lasts for roughly 20 years, about 5% of current customers will consider replacing their heating equipment with electric heat pumps every year. The analyzed Integration Analysis scenarios both need roughly all of that 5% annual turnover to electrify starting in 2030, and most heating equipment installed in the 2030s will still be in operation in 2050, regardless of efforts to ramp up heat pump adoption after that. This leaves little margin for error if heat pump adoption lags due to the other considered challenges.[98]

- **Rapid pace and increasing cost of building efficiency retrofits.** All scenarios in this analysis assumed that, from 2020 to 2050, building retrofits will reduce building heating and cooling loads by an average of 30% and that other efficiency improvements will reduce other end use electric demand by 15%. This is a high rate of efficiency improvement that will need coordinated action across efficiency programs. As energy efficiency programs address the low-hanging fruit (i.e., the buildings that are easier to retrofit and the opportunities that are more cost effective to implement), the cost of efficiency improvements for remaining buildings will likely increase over time.

- **Barriers to building shell and efficiency installation.** Significant building shell efficiency investments are necessary for each analyzed scenario. For some buildings, those efficiency improvements could mean deep changes to the building façade or interior structure. Insulation may also first require other structural enhancements, such as replacement of knob-and-tube wiring and asbestos or lead abatement, especially in older homes. National Grid's Downstate New York gas service territories may be particularly prone to these types of challenges, given the relative age of buildings in KEDNY and KEDLI shown in Table 4-2. These prerequisite building improvements could delay or defer necessary efficiency improvements.

[98] Note that the CEV.NY scenario will require a similar level of annual heat pump adoption as the other scenarios, but it assumes that a larger share of heat pumps will be installed in hybrid heating systems. This allows for customers with functional heating equipment to install a heat pump and utilize its efficient heating for most of the year, even if the pre-existing heating equipment is relatively new.

Table 4-2. Residential Building Vintage by Region

Year Built	New York State	NMPC Gas	KEDNY	KEDLI
Built 2000 or later	9%	10%	8%	7%
Built 1980 to 1999	14%	20%	9%	14%
Built 1960 to 1979	22%	22%	19%	30%
Built 1940 to 1959	23%	18%	23%	35%
Built 1939 or earlier	32%	29%	41%	14%

Note: "Year Built" categories aggregated to 20-year increments

Source: 2020 American Community Survey

- **Limitations on supply chain and workforce*.*** Under each scenario, most households will be retrofitted with efficiency improvements before 2050, and the number of heat pumps installed annually throughout New York State will increase by an order of magnitude over the next 5-10 years.[99] This level of home improvement, weatherization, and heat pump deployment activity will require a significant shift in the existing marketplace for HVAC and home retrofits, both to supply that number of heat pumps and to have a sufficient workforce to install and service them. Manufacturing capacity, supply chain issues, and the availability of a knowledgeable and skilled workforce may prevent the heat pump and home retrofit markets from meeting accelerated demand in the coming years. Customers will also need a way to differentiate contractors that are familiar with proper installation and maintenance practices and high-efficiency systems.

- **Customer willingness/perceptions*:*** Customers' attitudes, awareness, and perception of electric heating technologies presents a potential barrier to widespread adoption. For example, customers may not recognize that a ductless mini-split heat pump may be an option over adding ductwork to a home. Another barrier is that changes to customers' system configurations (e.g., replacement of a furnace with a GSHP) also require advance planning rather than simply replacing on system failure. Recent studies completed in the Northeast indicate that customer awareness of heat pumps is generally low.[100] Additionally, installation of heat pumps may carry similar building-readiness challenges as building shell upgrades, such as the potential need for electrical upgrades, asbestos remediation, or lead abatement.

4.2.1.2 Options to Address Challenges

Some potential options to address these challenges are listed below:

- **Workforce training programs.** New York State may need to deploy more workforce training programs to meet a growing need for a skilled and expanded energy efficiency and clean energy workforce. There may be a need for re-training and targeted programs to produce a skilled workforce, especially as the current workforce evolves to support new technologies and energy infrastructure build-out. For example, pathways with a

[99] Annual residential heat pump installations is assumed to range from 70,000-275,000 per year across analyzed scenarios during the 2030s.

[100] For example, A recent study commissioned by National Grid of Rhode Island identified that their customers had generally low awareness of heat pump technology. J. Erickson, M. Hobbs, C. McCarthy, A. Pandey. "Rhode Island Strategic Electrification Study", December 23, 2020. Available at: **http://rieermc.ri.gov/wp-content/uploads/2021/01/rhode-island-strategic-electrification-study-final-report-2020.pdf**

greater share of hydrogen or network geothermal will need more workforce that are skilled in these areas to support these efforts. Most customers also rely on their HVAC installer to inform them of the proper equipment to install, according to National Grid of Rhode Island's Strategic Electrification Study.[101] This means that a well-trained workforce will also lead to a better-informed customer base. New York's Clean Heat Program includes funds for workforce growth and training.

- **Coordinated, geotargeted customer programs** (e.g., demand-side management and heat electrification). Each of the scenarios analyzed relies on the majority of New York State customers participating in energy efficiency and/or electrification programs. Coordinating participation, with particular focus on disadvantaged communities and vulnerable areas of the electric or thermal distribution network, can minimize costs on the system. Widespread customer communications and education can support market acceptance and adoption.

- **Increased investment in building envelope and heat pump technologies.** Given the level of investment needed in building envelope and heat pumps, developing these technologies to improve efficiency and cost effectiveness could greatly improve adoption and the effectiveness of the scenarios. Investment in supply chains will also be necessary to satisfy the pending demand for these upgrades. The federal IRA will provide federal incentives to clean energy development and efficiency and equipment upgrades. State agencies in New York could assist building owners with understanding and applying for federal incentives.
- **Customer incentive programs**. Governments and utilities can help influence customer adoption of demand-side management and electrification by providing financial incentives such as upfront rebates when determined to be cost-effective and beneficial from a societal perspective, marketing these programs and providing other forms of customer education, and creating new taxpayer and ratepayer funding sources.

4.2.2 Supply Side Feasibility

Each of the analyzed scenarios forecast a large rate of growth for energy supply in New York. In less than three decades, electricity generation capacity will need to increase more than threefold in all scenarios to reliably supply the growth in electricity demand from the electrification of the buildings, industry, and transportation sectors. Rapid development of hydrogen production capacity will also be needed, with all scenarios needing at least 18 gigawatts of new electrolyzer capacity by 2050.[102] The development of new electricity and hydrogen capacity will result in changes in the way electricity generation capacity and transmission infrastructure is planned and evaluated, and the speed at which it is developed.

4.2.2.1 Challenges

Some of the supply side challenges are listed below:

- **Siting, permitting, and construction of new generation, transmission, and distribution facilities.** New utility-scale solar installations could occupy over 700 square

[101] Ibid.

[102] The Accelerated Transition scenario has the lowest buildout of H2 production capacity, requiring 1.55 MMDth/day by 2050, equivalent to 18.9 GW of electrolyzer capacity.

miles of land area.[103] Developers will be challenged to identify appropriate sites for new capacity development, and the state will be challenged to review a large volume of siting applications in a timely manner.

- **Expansion of electricity transmission, distribution, and storage.** In addition to new electricity generation development noted above, New York's electrical grid will need transmission and distribution upgrades to connect new generation facilities to population centers. Due to the intermittent nature of renewable energy sources, energy storage facilities and connections to neighboring regions will also be needed (the costs of energy storage and interstate transmission are included in our analysis). Additionally, geographic areas with high-quality renewable resources (i.e., with high wind and sufficient solar radiation) may be dispersed and distant from population centers and existing transmission lines, necessitating more investment to connect to the grid. Present-day laws governing the approval of interstate electricity transmission lines and the use of eminent domain authority to obtain the easements over land necessary for such lines may challenge the construction of such lines.[104]

- **Limitations on supply chain & power sector workforce.** The American Public Power Association recently published an issue brief noting that utilities are experiencing shortages of distribution transformers, smart meters, conductor materials, skilled labor, and other necessities.[105] Faced with an aging and retiring workforce, utilities may be challenged to recruit, train, and retain new employees.

4.2.2.2 Options to Address Challenges

Some potential options to address these challenges include:

- **Streamline the siting and permitting process.** Large-scale generation and transmission projects often face delays during the permitting process. New York could investigate ways to streamline the permitting and approval process for generation and transmission infrastructure. Such an investigation could examine restrictions and requirements at the local, state, and federal level to identify impediments and ways to accelerate development.

- **Facilitate regional planning and coordination.** The development of regional transmission infrastructure could be accelerated by new and different regional planning approaches. For instance, EPAct 2005 allows three or more contiguous states to enter interstate compacts to establish regional siting authorities to determine the need for future transmission facilities within those states and carry out the transmission siting

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[103] This land requirement estimate is based on an examination of existing large utility solar installations listed at: **https://data.ny.gov/Energy-Environment/Statewide-Solar-Projects-Beginning-2000/wgsj-jt5f/data** For example, PSEGLI's solar installation in zip code 11786 has a capacity of 24.9 MW and occupies about 0.5 square miles of land.

[104] Klass, Alexandra B., Expanding the U.S. Electric Transmission and Distribution Grid to Meet Deep Decarbonization Goals (September 6, 2017). Environmental Law Reporter, Vol. 47, 2017. Available at SSRN: **https://ssrn.com/abstract=3033829** or **http://dx.doi.org/10.2139/ssrn.3033829**

[105] APPA (2022). "Critical Infrastructure and Supply Chain Constraints" Available at: **https://www.publicpower.org/system/files/documents/Supply%20Chain%20Issue%20Brief.pdf**

responsibilities of those states.[106] Alternatively, transmission planners in New York could be required to consider regional benefits in making siting determinations.

- **Accelerate funding, programs to support clean energy workforce development.** NYSERDA is collaborating with educators and service providers to offer training programs for new and current employees. Additional funding could support clean energy workforce development and training in New York, through programs that create a sustainable pipeline of talent by supporting apprenticeships and formal training opportunities. The IRA may accelerate workforce investments with provisions that offer enhanced incentives to investors that comply with certain apprenticeship requirements.

As New York transitions its energy grid, an important consideration for National Grid is to ensure that the change does not unequally benefit certain groups while proving a detriment to others. A variety of factors, including income, location, home age, surrounding environment, and access to information can all influence whether certain groups are willing and able to transition from gas to electricity. These issues present notable challenges that must be thoughtfully approached by policymakers, regulators, and utilities to ensure that the benefits of the transition are equitably distributed across the entirety of the state's population.

4.2.3 Customer Affordability & Equity

Achieving the CLCPA targets will likely have significant cost impacts for New York State energy customers. These costs represent a challenge that will need to be addressed for any of the scenarios to materialize. Further, meeting emissions reduction targets is only one of the CLCPA goals; a key focus of the CLCPA is equitable decarbonization, which warrants particular attention toward disadvantaged communities as defined in Section 1.4.1.3.

A further challenge for achieving a fair and equitable energy transition is recognition that the burden of energy transition costs will likely have disproportionate impacts on those who remain on the gas distribution system absent policy and regulatory intervention. New homes and buildings will be less expensive to transition through efficiency measures, electrification, or other technology investments than older buildings. Older homes tend to have higher energy bills, more structural barriers to upgrades, and are disproportionately occupied by lower-income customers, particularly in disadvantaged and environmental justice communities. Higher income customers are better positioned to make energy transition investments, potentially leaving lower income customers saddled with the ongoing costs associated with investments previously made by the gas utility to serve since departed customers.

Note that this report does not advocate for a particular solution for addressing embedded cost risk. Policymakers and regulators in New York will need to seriously consider these issues and take appropriate steps to ensure the continued financial health of utilities essential to the public good while also balancing customer cost considerations, including fair and equitable cost recovery and allocation.

4.2.3.1 Challenges

Some of the other customer affordability & equity challenges are described below:

[106] Alexandra B. Klass, *The Electric Grid at a Crossroads: A Regional Approach to Siting Transmission Lines*, 48 UC Davis L Rev. 1946 (2015). Available at: **https://lawreview.law.ucdavis.edu/issues/48/5/Articles/48-5_Klass.pdf**

- **Upfront cost of efficiency and heating equipment upgrades.** Each of the scenarios needs major investment by customers in energy efficiency improvements and heating equipment upgrades. The CAC's Integrated Analysis estimates that the cost of a cold-climate ASHP with accompanying building shell upgrades for an older single family home to be about $21,000 ($10,000 to replace a fossil fuel boiler/furnace alone) and $40,000 for a GSHP system. While utility, state, and/or federal incentives can reduce the upfront cost to customers, those incentives are typically funded by customers, which raises additional questions regarding how to socialize costs appropriately. In National Grid's gas service territories, between 57% and 76% of residential buildings were built before 1970 (Table 4-2), housing that may be more expensive to upgrade than newer structures. These sizeable upfront costs need to be addressed – with ample consideration for equity issues and affordability challenges – for the state to meet its climate goals. And since building envelope measures and other work needed to make buildings electrification-ready are more costly and have longer payback periods, this makes them more difficult to fund under current utility program parameters and budgets

- **Increased cost of space heating bills in the short-term for electric heating customers.** However, in order to reach the CLCPA targets in each scenario, heating electrification must ramp up through 2030 and beyond. Regardless of whether this electrification is incentivized upfront or mandated, electrified customers will likely have higher energy bills in the short-term.

- **Increased cost of space heating bills in the long-term for thermal customers.** As identified in Section 3.7.2, under the current regulatory structure thermal prices will increase around 2040 in all scenarios. This could create upward rate pressure for remaining gas customers, particularly those who rely solely on gas to meet their heating needs. If a large number of customers depart the gas system or decrease their gas consumption either by fully electrifying their home or building or partially electrifying (e.g., installation of hybrid heating systems), the fixed costs associated with managing the gas system, including the remaining undepreciated balance and financing of existing assets, will be allocated to a declining customer base under current ratemaking practices.

- **Disproportionate impact on low-income customers.** Higher-income households will likely transition to electrification more quickly because they can afford the higher upfront costs of electric heating equipment and efficiency upgrades which will then save them money over time. Absent policies and measures to assist low-income and DACs with the energy transition, the customers remaining on the gas system are therefore more likely to be low-income and disadvantaged communities (DAC) households that, barring regulatory intervention, will be left to pay higher rates for gas system maintenance due to fewer customers on the system. This exacerbates an already challenging issue where, nationally, the median energy cost burden on lower-income households is three times higher than non-low-income households.[107] For National Grid territories, this issue is of particular importance to NMPC Gas and KEDNY, where median incomes are less than the state median as seen in Table 4-3. Without intervention, the energy transition could widen the economic disparity within and between New York communities.

[107] American Council for an Energy-Efficient Economy, Energy Burden Report 2022. **https://www.aceee.org/energy-burden**. Accessed December 2022.

Table 4-3. Household Annual Income in 2020

Household Annual Income	New York State	NMPC Gas	KEDNY	KEDLI
Less than $14,999	11%	9%	12%	5%
$15,000 to $49,999	26%	30%	26%	17%
$50,000 to $99,999	27%	31%	27%	24%
$100,000 to $199,999	24%	24%	25%	33%
$200,000 or more	12%	6%	10%	21%
Median Income	*$74,520*	*$59,863*	*$72,028*	*$112,699*
Mean Income	*$105,553*	*$81,830*	*$99,559*	*$146,147*

Note: “Household Annual Income” categories aggregated

Source: Guidehouse analysis of 2020 American Community Survey 5-Year Data by County

- **Equity and compounding challenges.** While each of the challenges identified here are difficult individually, they are all faced acutely and have a compounding effect on low and moderate income customers and those in disadvantaged communities. Older buildings, which are more likely to need additional remediation and cost to improve efficiency, are more common in disadvantaged communities. Where these efficiency improvements may be delayed or deferred, a larger, more expensive heat pump would likely be necessary to sufficiently heat the home. Absent intervention and when paired with the relatively high starting cost and relatively high cost of operation in the short-term, disadvantaged communities could be some of the last groups to electrify. As remaining thermal customers, under the current regulatory structure they will then be paying relatively higher thermal heating bills. In summary, facing one of these challenges increases the likelihood of facing others.

- **Equitable siting of infrastructure investments.** Each scenario calls for major energy system infrastructure investment, such as new electric generation facilities and hydrogen pipeline retrofits. Siting and building these projects may be particularly challenging in densely populated areas, such as KEDNY. Historically, disadvantaged communities have been disproportionately impacted by the siting and construction of new infrastructure development. An important consideration then will be how and where these infrastructure projects will be built and how communities are engaged in the process.

4.2.3.2 Options to Address Challenge

Some potential options to address these challenges are listed below:

- **Modified depreciation approaches to advance recovery and balance near and long-term affordability.** The Commission has taken positive steps to addressing affordability challenges by recognizing in its recent order on the gas supply planning process that “failure to fully depreciate assets in a timely fashion while LDCs still have robust customer base may lead to stranded costs” and ordering the gas utilities to develop depreciation studies that consider different scenarios. One alternative depreciation approach that could more equitably distribute costs to remaining gas customers is the Units of Production (UOP) method. This is a method of depreciation whereby capital costs are allocated equally to each unit of production rather than in equal amounts per year—for example, a capital cost to the gas network would be allocated over the lifetime of the project based on forecasted usage of the asset. Therefore, more of the capital cost would be recovered during periods when more customers are on the gas system and lower capital costs would be recovered as customers transition to electricity. This is a more equitable method of distributing capital costs that ties costs recovery to number of customers, thereby reducing the likelihood of total system costs falling disproportionately on future gas customers. The Companies' November 2022 analysis found that applying this approach to the CEV scenario leads to bill impacts that are closest to a business-as-usual trajectory. However, the study also finds that fore high-electrification scenarios, transition to a units of production approach is not sufficient to avoid exponential growth in revenue requirements per customer. The study recommends that in the near term, depreciation rates be set at the upper range of reasonableness, while still balancing impacts on current customers, and that more fundamental reforms to depreciation be determined based on an understanding of the future state of the gas business and how it will evolve over time under that vision.

- **Longer-term socialization of gas network costs**. Another option to address elevated thermal system prices is by adjusting the denominator of thermal prices and socializing some of the thermal system costs to the electric system. This could take the form of an electric utility-funded exit fee, wherein the electric system pays some portion of the thermal asset depreciation expenses that the departing thermal customer would have paid.
- **Development of energy transition equity programs.** New York State could improve access to clean energy technologies and demand-side management measures through energy transition equity programs – income-based and community-based incentive structures and geotargeted deployments designed to improve access to clean energy, demand-side management programs, electrification programs, and thermal energy networks such as networked geothermal systems. Funding for these programs could come through multiple avenues including direct funding from the federal or state government and funds generated through an energy transition surcharge or other rate rider included on electricity and/or gas utility bills.
- **Community outreach and stakeholder engagement.** Given the potential impacts of infrastructure projects on communities, stakeholder engagement should begin early in project development to enable community input on siting decisions as well as opportunities to ensure community benefits. To the extent that projects are being considered in DACs, enhanced efforts may be needed to ensure that adverse impacts are minimized and that community benefits are maximized.

4.2.4 Energy System Considerations

In all scenarios, the analysis shows that New York's energy system will need a significant scale up of energy infrastructure and will require changes in the way the electricity and gas systems operate. These electric and gas delivery systems will grow more interconnected over time as the capability to convert between electricity and hydrogen will enable GHG reductions from different end uses. Development of renewable electric generation capacity will need to be coordinated with the scale up in green hydrogen supply; and hydrogen production capacity and storage will be needed to meet peak electricity demand using hydrogen-fired gas turbines.

4.2.4.1 Challenges

The future integration of energy systems will require planning to be coordinated across multiple energy system participants, which will present a variety of challenges:

- **Coordination of electric and gas systems**. As in many other states, utilities in New York currently plan future supply and infrastructure development in relative isolation rather than considering the interdependencies between the electric and gas systems. It will be challenging for utilities to align planning cycles and adapt their planning guidelines to reflect a holistic perspective of energy system development.
- **Localized energy system constraints.** Energy system planning also occurs at the local level. For example, electric distribution system upgrades can be triggered on a feeder-level by a high level of electrification within a given neighborhood. Similarly, gas network decommissioning will require all customers served by the specific main to electrify. As result, localized tradeoffs will exist.
- **Requirement to procure least cost supply.** Current New York state law provides the authority for the Commission to require regulated gas companies to purchase or procure natural gas at the lowest available price, potentially limiting the ability for utilities to adopt and recover costs from renewable natural gas, green hydrogen, or geothermal sources. While it could be argued that this provision is only applicable to procurement of natural gas and does not prohibit the purchasing or development of lower carbon fuels regardless of cost in relation to natural gas, today, these fuels are relatively more costly to develop or procure.
- **Legal obligations and regulatory coordination.** Under current New York statutes, subject to limited exceptions, gas local distribution companies (LDCs) are obligated to provide service to prospective customers upon request.[108] The implication of this collection of statutory provisions is that while gas LDCs can make customers aware of alternative fuels (e.g., electricity) for heating and even provide incentives for existing customers to transition to electricity or other alternative fuels, they cannot require a customer to use alternative fuels, which may present challenges for targeted electrification initiatives.

4.2.4.2 Options to Address Challenges

Some potential options to address these challenges include:

- **Improve coordination of regulatory authorities to streamline development of decarbonization projects.** The Commission could proactively engage with other state and local regulatory bodies to help advance approved utility decarbonization projects through permitting and other regulatory approval processes to mitigate unnecessary project delays or rejections.

[108] New York Public Service Law Section 30, passed in 2020, declared it the policy of New York "that the continued provision of all or any part of such gas, electric and steam service to all residential customers without unreasonable qualifications or lengthy delays is necessary for the preservation of the health and general welfare and is in the public interest." The draft scoping plan of the Climate Action Council recognizes this provision when it states that "utilities have an obligation to continue to provide safe and reliable service" throughout the energy transition.

- **Pilot gas and electric planning programs that allow stakeholders to assess opportunities and avoid costs**. LDCs could fund innovative projects and programs to address regulatory barriers, test new business models, and enable projects that do not pass traditional cost-effectiveness tests. Pilot programs will be important for testing new methods and approaches and can help surface questions and complexities that need to be addressed before widescale deployment.
- **Continue to grow collaboration between electric and gas utilities.** Opportunities to improve coordination between electric and gas utilities include joint planning approaches to identify capacity constraints and capacity availability across both systems with the intent of optimizing capital investments; demand-side management programs and targeted electrification; cross-utility coordination, with regulatory oversight, of the setting of demand-side management program incentives; and coordination of hybrid heating programs, including use of integrated controls that optimize usage of electric and gas components.
- **Update clean fuel standards for thermal energy service to gas distribution customers to includes low carbon or carbon-free resources.** Developing new renewable gas production capacity will need a concerted effort by both distributors and regulators to simplify and concretize permitting procedures, incentivize long-term purchase procurement programs, and roll-out interconnection to existing gas infrastructure programs. National Grid and other providers could work with the Commission to revise cost-supply planning requirements to consider direct costs, long-term cost risks, and GHG emission reduction requirements for infrastructure planning. Doing this in conjunction with updating clean fuel standards to include low-carbon and carbon-free resources would provide clear regulatory guidance and market signals to inform utilities' long-term capital project plans.
- **Broaden procurement standards to include renewable fuels and enable long-term contracting to support project development.** A funding mechanism could be established for renewable fuel procurement that broadens procurement standards to include RNG and green hydrogen while enabling long-term contracting to support project development.
- **Alternative rate designs and rate restructuring.** Consideration of a new hybrid heating rate class or more general rate restructuring could better align the recovery of fixed costs with fixed, rather than volumetric, charges. Address allocation of energy transition costs, including consideration of cost allocation between electric and gas utilities through exit fees, non-bypassable charges, or other rate mechanisms applied to departing gas customers or all-electricity customers.
- **Consider regulatory changes to encourage gas system alternatives.** If considering statutory changes regarding gas LDCs' obligation to provide gas service, including the 100-foot rule, policymakers should consider: the proximity of the development to existing infrastructure and whether the area is subject to a high risk of stranded assets; whether the development is within high growth potential area; costs associated with service extension requirements; and the viability of alternative technologies to meet the customer's heating needs. Similar exceptions could be provided for areas geotargeted for electrification, networked geothermal, or other alternative heating technologies.
- **Align demand-side management and electrification incentives with expected benefits.** Develop processes and requirements that improve electric and gas utility

coordination and provide regulatory guidance on electrification, including the development of coordinated geotargeted programs that maximize the benefits of investments in demand-side management programs (i.e., energy efficiency and demand response), and heat electrification. Develop a fair and equitable method for allocating demand-side management and electrification incentive funding between electric and gas ratepayers.

4.2.5 Technology Readiness & Scalability

No single technology will be sufficient to transform New York's energy systems to meet CLCPA requirements. Rather, a coordination of multiple technologies, upgrades, and customer behaviors will be necessary to ensure a more sustainable future for the state. This study's three scenarios examined a mix of technologies, including mature technologies such as solar and wind production, heat pumps, and EVs; moderately mature technologies such as RNG and networked geothermal; and relatively new commercial technologies such as hydrogen usage for energy production and direct air carbon capture. Investment in technologies across the spectrum will be critical for both innovations in new technologies as well as in scalability for technologies that will help the state meet its climate goals.

4.2.5.1 Challenges

Some of the challenges associated with technology readiness are as follows:

- **Insufficient regulatory frameworks.** New low- and zero-carbon technologies present a path to decarbonization. However, regulatory uncertainty may reduce market appetite for wide scale investment, particularly for newer technologies. This issue may be compounded by murkiness in regulations for certain technologies: codes exist for established technologies such as ASHPs and renewables and, in July 2022, NY Senate Bill S9422 was passed to provide regulation for networked geothermal, however there will need to be code development regarding hydrogen and RNG. Code development includes consideration for safety, interoperability, meter calculation adjustments, and blend-grades, to name a few, and pose a barrier to investment for parties interested in piloting projects. Regulatory clarity will be essential to secure investment which, in time, will widen market acceptance of lesser established technologies to fill gaps potentially left by the roll-out of better understood technologies.

- **Feasibility of deployment and coordination**. Outside of technical feasibility, extensive coordination barriers exist for network-style projects, such as network geothermal, RNG interconnection, or any project that requires permits or easements on private property. Municipal and state level authorities and stakeholders often need to coordinate on these projects while ensuring buy-in of private individuals whose property the projects cross—this will necessitate extensive coordination prior to project execution to ensure that a project is not stalled mid-way through due to permitting, zoning, or stakeholder issues.

- **Scalability of present and future commercial technologies**. The past decade has seen innovation in renewable energy technologies such as wind and solar, with a significant decrease in costs for materials as well as understanding of necessary associated infrastructure. The next decade will likely see similar trends for RNG, networked geothermal, hydrogen, direct air carbon capture, and other newer commercial technologies, however this is not a definite outcome. Should these technologies face scalability barriers, then it could restrict the "tool-box" of low- and zero-carbon technologies that are available for New York to meet its climate goals.

4.2.5.2 Options to Address Challenge

Some potential options to address these challenges include:

- **Fund and deploy technology demonstrations and pilots, leveraging federal funding opportunities where possible**. As was mentioned in the previous section, dedicating resources to demonstration and pilot projects across the technology spectrum could spur the growth of these various industries. With the passage of the Bipartisan Infrastructure Bill and the IRA, there is more federal funding available for decarbonization projects now than has ever been available in the past. Further, there is precedent in New York to consider encourage projects aligned with state policy objectives. For example, the NY PSC permitted electric utilities to set-aside up 0.5% of delivery service revenue for demonstrations[109].

- **Clarify utility role in delivering RNG:** Policymakers and regulators in New York, including the Commission, will play an important role in enabling National Grid and other New York gas utilities to advance RNG production and distribution efforts. For example, regulators should clarify the gas utility's ability to procure and recover costs for RNG.

[109] New York Public Service Commission, "Order Adopting Regulatory Policy Framework and Implementation Plan", Case 14-M-0101, February 26, 2015. **https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0B599D87-445B-4197-9815-24C27623A6A0}**

4.3 Next Steps for National Grid

Based on this analysis, Guidehouse has organized potential next steps for National Grid into four categories: affordability, infrastructure, technology and workforce, and demand reduction.

Affordability and Equity

- Continue to participate in the development of energy transition equity programs, including income-based and community-based incentives and geotargeted demand-side management programs to meet and exceed the CLCPA's requirement that at least 35% of benefits of clean energy investments accrue to disadvantaged communities.
- Consider how infrastructure investments might be sequenced to prioritize delivery of benefits to disadvantaged communities.
- Continue to explore modified depreciation approaches to advance recovery and balance near and long-term affordability.

Infrastructure

- Develop a comprehensive strategy for leak-prone pipe replacement that prioritizes the safety and emissions benefits from near-term pipe replacements, while identifying opportunities to avoid infrastructure investment where feasible.
- Support development of in-state RNG production, leveraging federal funding opportunities where possible.
- Initiate planning for the development of hydrogen infrastructure, starting with a planning study to identify the inter-regional infrastructure requirements, leveraging federal funding opportunities where possible
- Develop community scale network geothermal systems to avoid replacement of leak prone pipe and reduce peak energy demand.

Technology and Workforce

- Fund and deploy technology demonstrations and pilots for networked geothermal systems, leveraging federal funding where possible.
- Fund and participate in research exploring hydrogen blending in distribution networks, to better understand leakage risks and mitigation strategies, and monitor other hydrogen blending studies designed to test the safety and operational impacts on the gas system, appliances, and local air quality.[110]
- Continue workforce skill development across the clean energy economy which includes, HVAC, energy efficiency, network geothermal, renewable natural gas, hydrogen, utility scale solar, offshore wind, transportation electrification, among others.

Demand Reduction

- Expand energy efficiency, demand response, and customer incentive programs, and assist customer with accessing federal incentives, while making necessary technology investments to enable the success of these programs.

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[110] CPUC Acts To Advance Understanding of Hydrogen's Role As Decarbonization Strategy. **https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-acts-to-advance-understanding-of-hydrogen-role-as-decarbonization-strategy**.

- Expand customer education programs to improve awareness of technologies like hybrid heating and networked geothermal.
- Continue to support the development of workforce training programs to meet a growing need for a skilled and expanded energy efficiency and clean energy workforce.
- Explore innovative financing mechanisms and other new program offerings to complement energy efficiency rebates
- Continue to explore non-pipe alternatives on LPP segments and to solve localized gas system constraints.

5. Conclusion

At the time of its enactment, the CLCPA is the most ambitious climate legislation that a U.S. state has passed, and its implementation will require a comprehensive transformation of the state's energy systems. National Grid and Guidehouse defined three scenarios that meet the Climate Act's requirements and jointly agreed on key assumptions with engagement from stakeholders. Guidehouse used its Low Carbon Pathways model to estimate the investments that will be necessary in each scenario for electric and gas systems (generation, transmission, distribution and for end user buildings and equipment).

The study revealed that the energy transition will be a significant undertaking but finds that a diversified approach that continues to utilize the gas network to support decarbonization is less costly than approaches that prioritize full electrification and gas network decommissioning. A large amount of investment will be needed to extend and upgrade New York's energy system, to retrofit customer buildings, and to replace energy consuming appliances. Compared to the Integration Analysis scenarios, the analysis shows lower total NY State system costs for the CEV.NY scenario due to more diverse investment across sectors and later in time.

Intervention will be needed to maintain reasonable gas utility rates for customers. Under the current regulatory environment, with no cost sharing across energy systems, unitized thermal system costs begin to grow significantly starting around 2040. If the energy transition described in the findings above is not accompanied by a regulatory transition, then gas utilities' normalized revenue requirement per customer is projected to increase at least threefold by 2045.

A further challenge for achieving a fair and equitable energy transition is recognition that, absent policy and regulatory intervention, the burden of energy transition costs will likely have disproportionate impacts on customers who remain on the gas distribution system. Without policies and measures to assist low-income and DACs with the energy transition, these customers are more likely to be low-income and households in disadvantaged communities that, barring regulatory intervention, will be left to pay higher rates for gas system maintenance due to fewer customers on the system. Modified depreciation approaches coupled with customer incentives, energy equity programs, and other interventions could ease the transition costs for low- and moderate-income customers.

Many challenges will need to be addressed to achieve CLCPA targets. This study discusses some of those challenges and potential options to address them. Policymakers and regulators in New York will need to consider these issues and take appropriate steps to ensure the continued financial health of utilities essential to the public good while also balancing customer cost considerations, including fair and equitable cost recovery and allocation.

Appendix A. Integrated Energy System Modeling

To determine the least cost way to reduce GHG emissions from New York's energy system, this study used Guidehouse's Low Carbon Pathways (LCP) model, a proprietary energy system model. The LCP model optimizes the build out of supply capacity, transmission interties, and gas and electric storage assets to meet future energy demand, simulating the hourly dispatch of electricity, hydrogen, and methane resources. The analysis models the electricity and gas systems and reflects the linkages and dependencies that exists between electricity, methane (both geologic and renewable natural gas), and hydrogen.

In this project, Guidehouse applied the LCP model to optimize the supply of electricity, hydrogen, and methane to meet demand in three 2050 demand scenarios that comply with requirements of New York's Climate Act. The following describe some of the major features of the LCP model as applied in this project:

- Capacity expansion and dispatch optimization: Optimization of generation, storage, and interconnections assets across the electricity and gas (methane and hydrogen) networks.
- Lowest-cost net zero pathway: Optimized pathways to achieve compliance with NY Climate Act emissions requirements.
- Intra-annual temporal resolution: Uses representative and peak days to reflect the seasonal variability of electricity and gas demand loads and supply resources.
- Geographical resolution: Simulates the New York energy system, subdivided into five regions, and four neighboring regions: Ontario (IESO), Quebec (HQ), New England (ISO-NE), and PJM.

The LCP model is an integrated capacity expansion and dispatch optimization model used to identify the lowest-cost pathway to a low carbon energy system. The cost-optimization engine of the LCP model minimizes the net present value of the total system costs over the analyzed study timeframe while considering various constraints at the energy system level (e.g., the buildout and availability of supply resources, the development of interconnections) and operational constraints at the individual technology level (e.g., the operation of power generation plants). The analysis solves the expansion and GHG emissions reduction of the electricity and gas (hydrogen and methane) system by adding new supply capacity over time (e.g., onshore/offshore wind, solar).

As an integrated energy system model, the cross-sector interactions between electricity, hydrogen, and methane are an integral part of the analysis (e.g., electrolyzers increase demand for electricity, hydrogen gas turbine usage increases hydrogen demand). The analysis also models the use of transmission interties across regions (e.g., power lines and pipelines) and storage assets (e.g., gas and electricity storage) to balance supply and demand. The modeling methodology is based on a "copper plate" for each region, meaning the focus of the analysis is primarily on inter-connections (across regions) rather than intra-connections (i.e., network capacity within each region; although nominally allowed for in the energy system costs, it is not the focus of the modeling).

The LCP model uses a nodal network to model an interconnected energy system, each node with its unique energy supply and demand varying over time. The LCP model is configured to a geographical scope of New York and the four neighboring regions previously mentioned. All existing electricity and gas interties between regions are simulated in the model. The model also allows for existing interties to be expanded or for new ones, where applicable, to be constructed and for the option to repurpose methane interties for hydrogen.

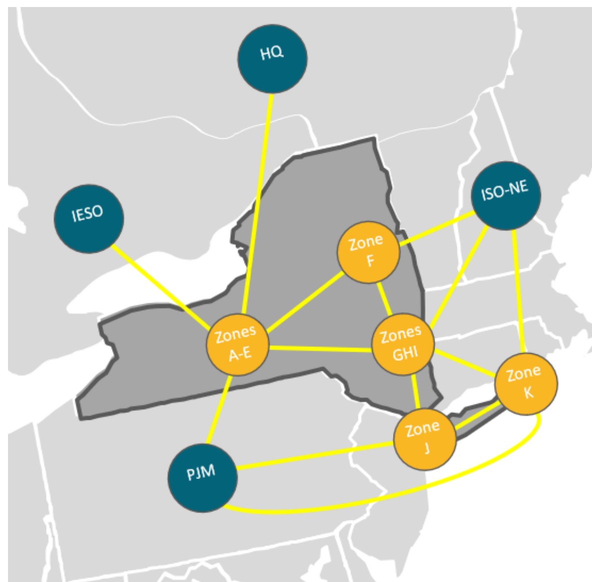
A description of the main configuration parameters of the LCP model and several other modeling considerations is presented in Figure A.

Figure A-1. LCP Model Configuration and Key Modeling Considerations

Geographic Scope

This study models five regions in New York State (NY) and four neighboring regions: Ontario (IESO), Quebec (HQ), New England (ISO-NE), and PJM. All regions are modelled as individual copper-plate nodes, each with its unique energy supply and demand conditions varying over time.

- Regions are modelled as an interconnected network of nodes with energy infrastructure connecting a node with its neighboring nodes. The map at right shows the interties between NY regions and neighboring regions.
- Electricity transport between each region is optimized model-endogenously. Electricity demand and supply capacities in each of the four neighboring regions is scenario-defined and largely based on publicly available information.
- Methane is imported from PJM and ISO-NE. Hydrogen can be imported from any neighboring region. However, based on the projected costs of hydrogen imports compared to in-state production, the LCP model assumes that New York State will produce sufficient hydrogen to meet forecast demand.



Energy Carriers

Demand scenarios forecast energy demand in NY State across three energy carriers: electricity, hydrogen, methane. Methane demand reflects demand for natural gas, RNG, and natural gas + CCS. The demand scenario forecasts only reflect *direct* energy demand (e.g., energy demand from end users) but not *indirect* energy demand (e.g., electricity demand needed for hydrogen production). Indirect energy demand is determined within our model and is impacted by various factors including the availability of surplus electricity, gas/electricity storage and energy imports.

Analysis Timeframe

Demand scenarios extend from 2020 to 2050, creating snapshots of the New York energy system every 10 years: in 2030, in 2040, and in 2050. The year 2020 is used as the base year of the analysis and is calibrated to match the current supply mix of the New York electricity and gas systems. 2050 is used as the final year of the analysis as it is the target year for New York to achieve Climate Act emissions requirements.

Temporal Resolution
To reflect the variability of demand loads and supply resources in New York and in neighboring jurisdictions, the LCP model employs four representative seasonal days (winter, spring, summer, fall), two peak days (summer peak and winter peak), and one winter peak day when electric generation from wind resources is limited.
Emissions and Sectoral Scope
The focus of this analysis is achieving the NY Climate Act's GHG emissions requirements. Because the scope of the LCP analysis is the energy system—more specifically energy demand from buildings, industry, transport, and the power sector—some sectors are excluded from LCP modeling. Emissions from agriculture, land use, waste, or embedded emissions from products or materials are exogenous to the LCP model. This analysis adopts the GHG emissions findings published in the CAC's Integration Analysis for these exogenous emissions sectors.

Source: Guidehouse

guidehouse.com